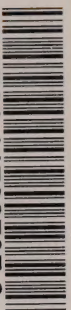



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Canadian Hydrocarbon **Transportation** System

TRANSPORTATION ASSESSMENT • August 2005

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ACRONYMS AND ABBREVIATIONS

AOS	Authorized Overrun Service
Alliance	Alliance Pipeline Ltd.
B.C. System	TCPL B.C. System
Chevron	Chevron Canada Limited
Cochin	Cochin Pipe Lines Ltd.
DBRS	Dominion Bond Rating Service
EBIT	Earnings Before Interest and Taxes
Enbridge	Enbridge Pipelines Inc.
Express	Express Pipeline Limited Partnership
FFO	Funds from Operations
Foothills	Foothills Pipe Lines Ltd.
FT	Firm transportation
IPI	Implicit Price Index
IT	Interruptible transportation
LNG	Liquefied natural gas
M&NP	Maritimes and Northeast Pipeline
MPL	Montreal Pipe Line
NEB or Board	National Energy Board
PNGTS	Portland Natural Gas Transmission System
ROE	Return on Equity
S&P	Standard & Poor's
SOEI	Sable Offshore Energy Inc.
T-South	Transportation South Zone on Westcoast
Terasen (TMPL)	Terasen Pipelines (Trans Mountain) Inc.
TNPI	Trans-Northern Pipeline Inc.
TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada or TCPL	TransCanada PipeLines Limited
U.S.	United States
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc.

UNITS

Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
MMcfd	Million cubic feet per day
GJ	Gigajoule
m ³ /d	Cubic metres per day
10 ³ m ³ /d	Thousand cubic metres per day
MW	Megawatt

FOREWORD

As part of its regulatory mandate, the National Energy Board (the Board or NEB) continually monitors energy and transportation markets to ensure that Canadians derive the benefits of economic efficiency. To further assist in its monitoring efforts, the Board identified a need in its *2004-2005 Report on Plans and Priorities* to implement a performance measurement system for pipeline tolls and tariffs, including the financial health of the pipeline industry.

This report provides an assessment of how the Canadian hydrocarbon transportation system is currently functioning and sets out the framework the Board will use for future assessments.

The data contained within this report is based on publicly available information collected and monitored by NEB staff. In identifying some of the emerging issues around the transportation system, the Board also benefited from discussions with members of the investment community. A draft of the report was sent to the Canadian Energy Pipeline Association and the Canadian Association of Petroleum Producers for comment prior to its release.

Any comments on the report or suggestions for further analysis can be directed to:

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If a party wishes to rely on material from this report in any regulatory proceeding, it can submit the material as it can submit any public document. In such a case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

INTRODUCTION

The Canadian hydrocarbon transportation system moves over \$100 billion in petroleum products and natural gas to Canadians and export markets each year. In 2004, energy export revenue was almost \$59 billion, accounting for about 15 percent of total Canadian exports. Energy is essential to our daily lives and the ability of the pipeline transportation system to reliably and efficiently deliver this energy is critical to our country's economic well-being. The Board regulates the physical and financial operations of pipelines that cross interprovincial boundaries and the international boundary.

The Board has developed five corporate goals to ensure that its regulatory program provides value to Canadians. The third goal is that "Canadians derive the benefits of economic efficiency". To determine whether this goal is being achieved, the Board monitors energy and transportation markets for evidence that they are working well.

Each year the Board issues various Energy Market Assessment reports that focus on different aspects of Canadian energy markets. This is the first time that the Board has issued a report that focuses on the functioning of the Canadian hydrocarbon transportation system.

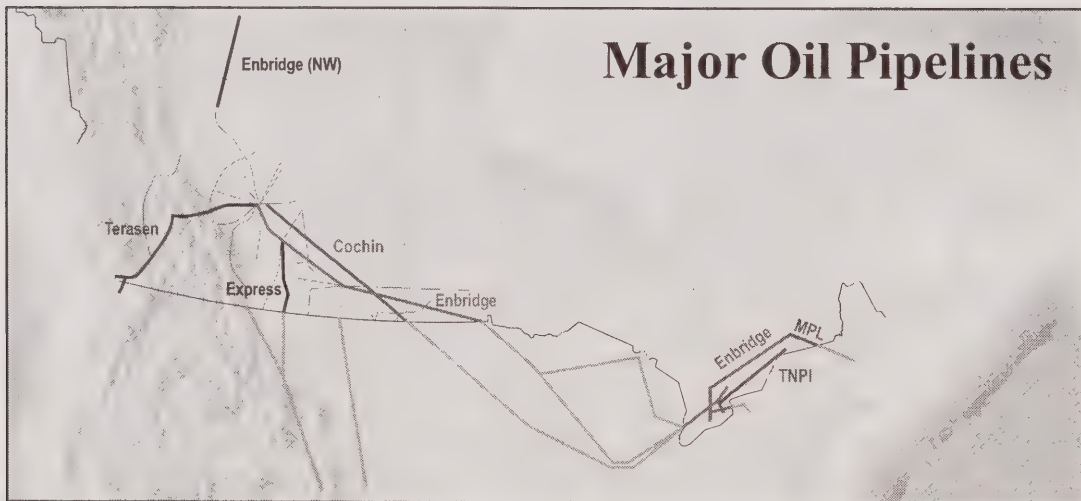
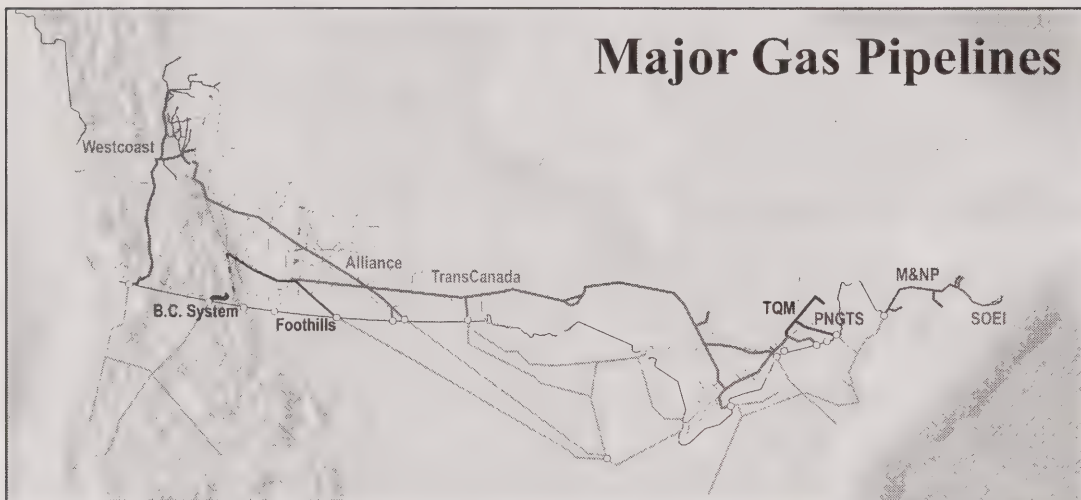
This report is similar to the Board's other market monitoring reports and its intent is to assess how well the Canadian hydrocarbon transportation system is working and to outline a system to monitor and measure the performance of the transportation system from year to year. This report should not be read as a regulatory document, like a Reasons for Decision. In this report, the Board is not making a determination on regulatory matters such as the appropriate rate of return on equity that should be earned by pipeline companies. Thus, the factors on which the functioning of the transportation system is assessed are not the same as those which are applied in a regulatory proceeding.

For the transportation system to work well, the Board believes that the following three outcomes should be achieved:

1. there is adequate pipeline capacity in place to move products to consumers who need them;
2. pipeline companies are providing services that meet the needs of shippers at reasonable prices; and
3. pipeline companies have adequate financial strength to attract capital on terms and conditions that enable them to effectively maintain their systems and build new infrastructure to meet the changing needs of the market.

To assess the extent to which these outcomes are being achieved, the Board used publicly available data for Group 1 regulated companies (see Figure 1). This group comprises the major pipeline companies that are subject to ongoing regulatory oversight by the Board. As these companies represent a major part of the Canadian transportation system, the data from these companies provides a good view into the overall functioning of the transportation system.

Gas and Oil Pipelines Regulated by the National Energy Board



THE CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

2.1 Adequacy of Pipeline Capacity

A key measure of the efficient operation of energy markets is that there is adequate pipeline capacity to transport crude oil, refined products, natural gas and natural gas liquids from producing regions to market areas.

This section examines the following factors to assess the current adequacy of the pipeline capacity:

- price differentials compared with firm service tolls for major transportation paths
- capacity utilization on pipelines; and
- the degree of apportionment on major oil pipelines.

The Board has generally taken the view that it is better to have some excess pipeline capacity than to have inadequate capacity. While there are costs associated with having excess capacity in terms of higher tolls for shippers, the costs associated with insufficient pipeline capacity are generally greater. When there is inadequate take-away capacity, natural gas or oil production is shut-in or shipped to less attractive markets, resulting in foregone revenues for producers, foregone royalty revenue for governments, higher commodity prices for downstream consumers, an inefficient allocation of supply and a negative signal to investors in the upstream sector. The assurance that adequate capacity is available to serve various market regions provides a strong incentive to invest in exploration and development.

Further, some excess capacity in the system provides flexibility in the market. For example, when gas demand and prices are high in California because of poor hydro-electric conditions, Canadian producers would like to move gas to that market. When cold weather strikes the U.S. Northeast and prices in that market increase, the existence of some spare capacity allows producers to swing supply to that market, meeting consumers' needs and helping prices to stabilize.

The importance of having adequate pipeline capacity in place is highlighted by the fact that the value of natural gas and oil transported in NEB-regulated pipelines far exceeds the cost of service on those pipelines (e.g., in 2004 the value of products transported was approximately \$100 billion compared with \$4.5 billion for the cost of providing transportation service).

2.1.1 Price Differentials and Firm Service Tolls

One measure of adequacy is based on the principle that, if adequate capacity exists, the price differential (or basis) between two points on a pipeline should be equal to or less than the cost of

transportation. As long as the price differential is less than the firm service toll plus fuel, the market is demonstrating that there is adequate pipeline capacity between the two pricing points. When there is inadequate pipeline capacity between two market points, the basis will exceed the cost of transportation. In a market with adequate capacity, sellers would generally redirect their product to the higher price market, thereby meeting that region's need for energy. Where inadequate capacity exists, the product cannot get to market and the price differential persists, resulting in higher prices for consumers and lost revenues for producers.

In order to use this measure, there must be reasonably good pricing data available. Two examples of price differentials compared with firm service tolls are provided below; one for transportation on TransCanada PipeLines Limited (TransCanada or TCPL) and one for transportation on Westcoast Energy Inc. (Westcoast).

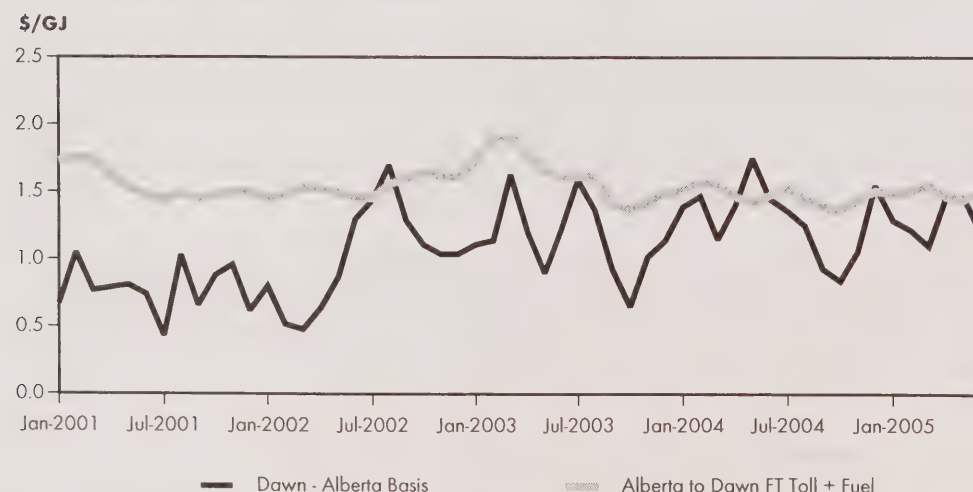
Figure 2 shows the basis between the Alberta border and the Dawn delivery point compared with the TransCanada firm service toll between the two points, including fuel costs. The fact that the basis is consistently lower than the firm service toll demonstrates that there generally has been excess capacity available on TransCanada since at least January 2001, although it appears that capacity between these two points has firmed up during the summer months since July 2002.

Figure 3 shows the basis between Compressor Station 2 on the Westcoast system and the Sumas export point compared with the Westcoast firm service toll between the two points (T-South or Southern Mainline), including fuel costs. Except for a few months, the basis has been lower than the transportation costs since February 2001, which indicates that there has been adequate capacity in place since that time¹.

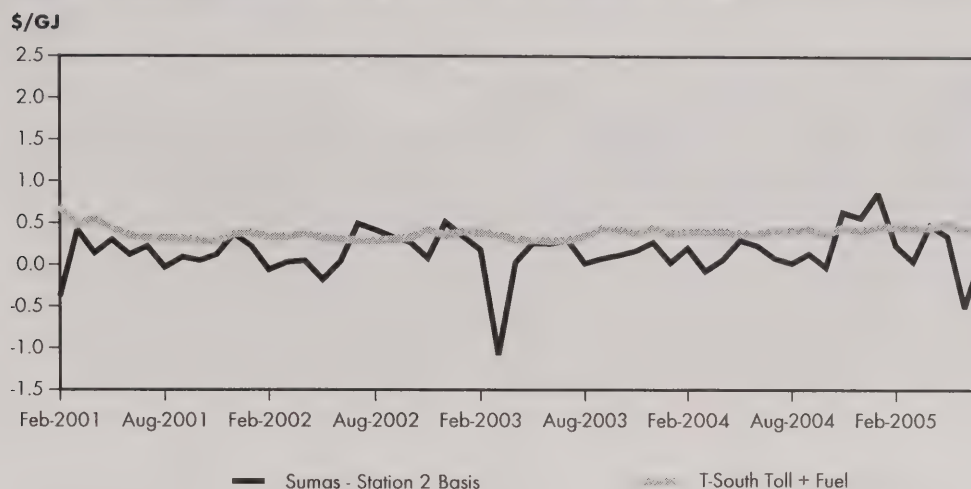
Dawn-Parkway Corridor

Although there is inadequate pricing data available, there is evidence that capacity is tight on the Dawn-Parkway corridor of the Union Gas system. After the close of a binding open season in December 2004, Union signed contracts with 22 parties for an expansion of its system between Dawn and Parkway. Following the consideration of Union's facilities application, the Ontario Energy Board

Dawn - Alberta Basis vs. TransCanada Toll and Fuel



¹ The negative price differential at March 2003 may be a data anomaly.

FIGURE 3**Sumas - Station 2 Basis vs. Westcoast T-South Toll and Fuel**

approved the expansion which is expected to be in service by November 2006. While not regulated by the NEB, this corridor is a key link between the Dawn hub and markets in eastern Canada and the U.S. Northeast.

2.1.2 Capacity Utilization on Major Routes

Where good pricing data is not available at major injection and delivery points on a pipeline system, another measure of adequate capacity is to monitor pipeline throughput compared with capacity. Capacity utilization is monitored for most large pipelines regulated by the Board.

The following figures show pipeline average monthly throughput compared with capacity on some of the largest pipeline systems regulated by the NEB, including TransCanada, Westcoast, Alliance Pipeline Ltd. (Alliance), Enbridge Pipelines Inc. (Enbridge), Terasen Pipelines (Trans Mountain) Inc. (Terasen (TMPL)) and Express Pipeline Limited Partnership (Express).

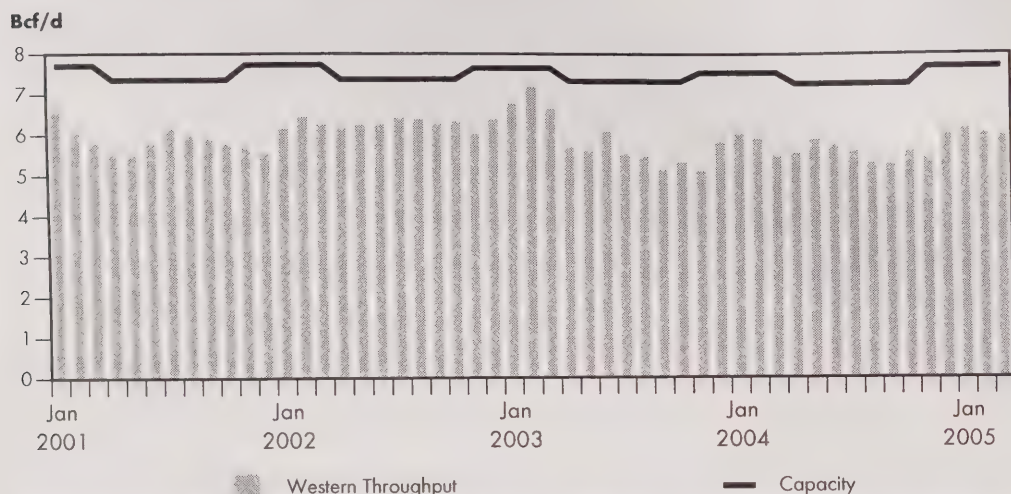
The volumes shown on Figure 4 are average monthly throughput² on the TransCanada Mainline and are approximately equal to the amount of gas flowing east on the Mainline from Saskatchewan. These volumes are compared with the design capacity of TransCanada's prairie line. Figure 4 shows that since April 2003, the prairie line has been operating at between 70 to 80 percent of capacity.

Figure 5 shows the average monthly throughput on Westcoast's Southern Mainline compared with capacity between Station 2 and the Sumas export point. This figure shows the seasonal nature of throughput on the Southern Mainline with more volumes being transported during the peak winter months and less volumes being transported during the summer months.

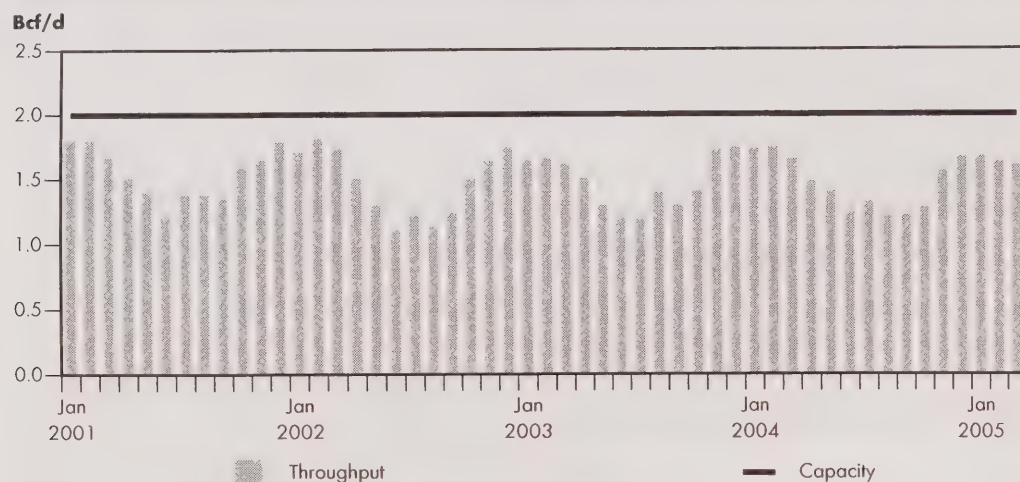
In Figure 6, throughput on Alliance's system is compared with the firm service contracted capacity of 37,534 10³m³/d (1,325 MMcf/d) and physical capacity, which has been calculated as the sum of the contracted capacity and capacity made available for Authorized Overrun Service (AOS). As shown, Alliance's capacity has been virtually 100 percent utilized since the commencement of its operations because of the high contract level and the offering of AOS, priced at only the cost of fuel, which has filled any additional capacity.

² Daily fluctuations in throughput are not shown on the figure.

TransCanada Mainline Throughput vs. Capacity



Westcoast Mainline Throughput vs. Capacity



It is somewhat difficult to assess utilization of the Enbridge system because it consists of several lines, most of which are dedicated to carrying specific grades of crude oil or natural gas liquids. As shown in Figure 7, since January 2001 Enbridge's mainline has been operating, on an overall average, at levels as low as 68 percent of capacity and as high as 86 percent of capacity. In the first quarter of 2005, Enbridge's mainline was operating at around 74 percent of capacity. Certain lines, particularly Lines 4 and 9 have been operating at or close to full capacity, with some apportionment (see section 2.1.3).

Terasen (TMPL) was operating at near capacity in 2003-04, with apportionment in January and March 2004. Given the high utilization rate, expected rising demand for pipeline space related to expected production growth in the oil sands, and increased shipments of heavy crude oil, Terasen (TMPL) applied in December 2003 for a 4 300 m³/d expansion. The Board approved this expansion and it went into service in September 2004. In the first quarter of 2005, Terasen (TMPL) operated at approximately 60 percent of capacity, mainly because of refinery turnarounds on the west coast (see Figure 8).

FIGURE 6

Alliance Throughput vs. Capacity

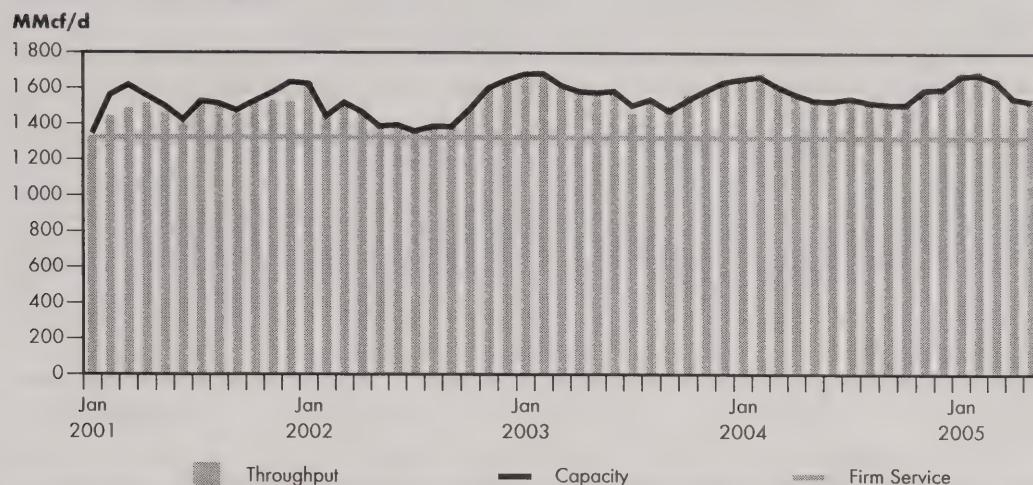
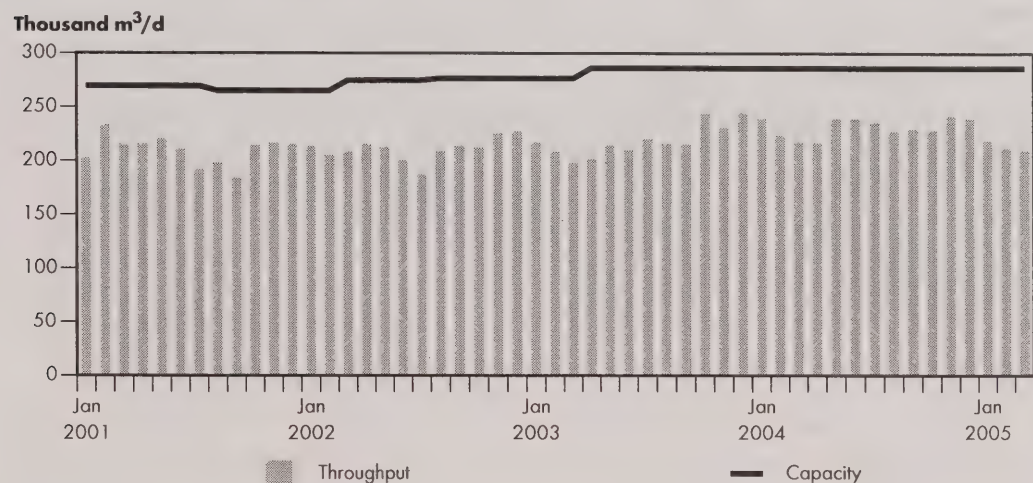


FIGURE 7

Enbridge Pipeline Throughput vs. Capacity

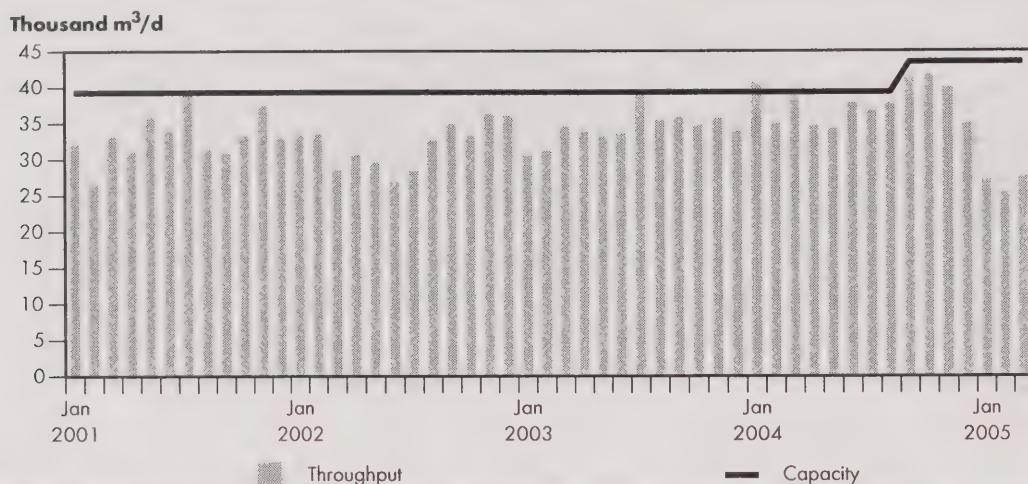


Express Pipeline Limited Partnership has been operating at full capacity for several years; at times exceeding 100 percent of its rated capacity (see Figure 9). On 1 April 2005, an expansion of 17 100 m³/d was completed. Unlike Enbridge or Terasen (TMPL), Express primarily operates with long-term financial commitments with its shippers. Given that shippers have financially committed to the system, they will tend to use their available space on Express before shipping on other systems.

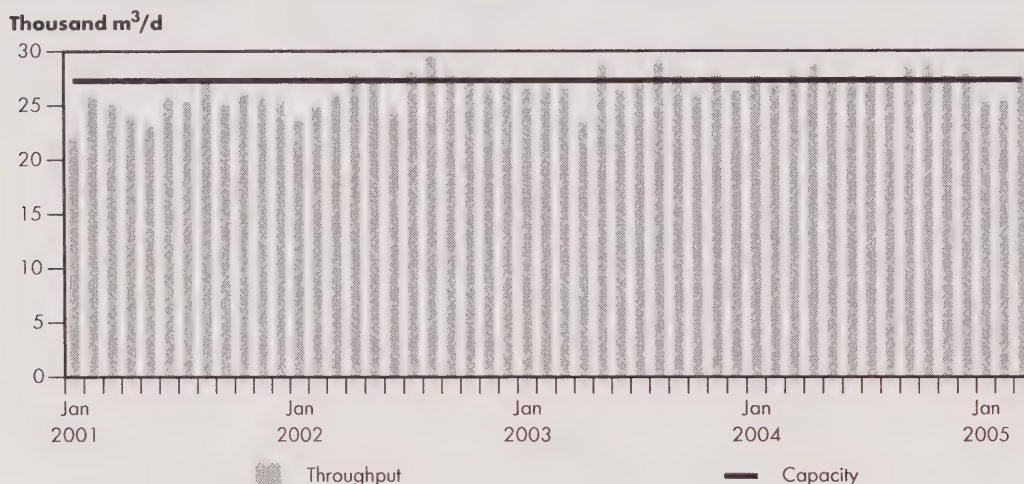
2.1.3 Apportionment

Oil pipelines operate for the most part as common carriers. On common carriers, shippers nominate their desired volumes for delivery into the pipeline on a monthly basis and have no contractual rights to the pipeline's capacity. Lack of adequate pipeline capacity occurs when shippers nominate more oil or oil products for transport than the pipeline can carry that month. When this happens, each of the shippers that nominate volumes is allotted or "apportioned" a share of the available capacity based on the capacity allotment agreement for each pipeline. Some recent apportionment data for Enbridge, Terasen (TMPL) and Cochin Pipe Lines Ltd. (Cochin) are shown below.

Terasen (TMPL) Throughput vs. Capacity



Express Throughput vs. Capacity



Enbridge

Enbridge's Line 2 and 4 are dedicated to the transportation of heavy crude oil, while Line 3 is dedicated to light and medium crude oils. In the first quarter of 2005, Line 4 was either marginally over subscribed or fully subscribed. In the third quarter of 2005, Enbridge is planning to switch service in Lines 2 and 3, thereby increasing heavy capacity by 39 000 m³/d.

Enbridge's Line 9 has a capacity of 38 150 m³/d and transports oil from Montreal to Sarnia. As shown in Table 1, apportionment has occurred fairly frequently on this line. One reason for this apportionment is increased shipments of crude oil produced from the Hibernia and Terra Nova fields which have high wax content and decreases operating capacity. Another reason is that foreign crude oil has been attractively priced and imports have been high in several months.

TABLE 1**Enbridge Apportionment**

	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05
Line 4 Apportionment	0%	0%	0%	6%	0%	0%	1%	0%
Throughput (10 ³ m ³ /d)	98.1	100.5	101.4	119.3	113	114.2	114.8	104.7
Line 9 Apportionment	21%	18%	0%	0%	4%	10%	0%	0%

TABLE 2**Terasen (TMPL) Apportionment**

	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05
Apportionment	24%	14%	14%	0%	0%	0%	0%	13% L 62% D
Throughput (10 ³ m ³ /d)	41.2	41.8	39.8	34.9	27.2	25.4	28.3	37.2

Terasen (TMPL)

On Terasen (TMPL), apportionment is calculated separately for volumes delivered to land-based and Westridge Dock destinations (shown as L and D respectively in Table 2). Apportionment in September through November 2004 was attributed to land-based nominations that were due to increased demand as well as maintenance on the system that reduced available capacity. Even with the capacity expansion that was completed in September 2004, there was apportionment in November due partly to greater demand by Washington State refiners. From December 2004 to March 2005, throughput fell and there was no apportionment for those months. The April 2005 apportionment of 13 percent for land-based volumes likely reflects increased nominations from the Washington refineries following plant turnarounds. The 62 percent apportionment for the Westridge Dock could reflect increased test shipments of heavier type crude oils.

As a result of periods of apportionment on Terasen (TMPL) since 2003, two applications have been filed with the Board. One is from Chevron Canada Limited (Chevron) for an order designating Chevron's refinery at Burnaby, B.C. as a priority destination for unapportioned delivery of crude oil from Edmonton. The second application was filed by Chevron Standard Limited, Neste Canada Inc. and Chevron for an order designating Chevron's refinery at Burnaby, B.C. as a priority destination for the unapportioned delivery of iso-octane from Edmonton.

Cochin

The capacity on Cochin is dependent on the type of product that is transported in the line and the time of year. Propane, ethane, ethylene and field-grade butane can all be transported on the line but the amount of ethylene nominated in a month affects the capacity. When there is a large amount of ethylene in the line, the capacity is reduced significantly. Cochin is still on pipeline restrictions since a rupture on the U.S. portion of the pipeline and a subsequent fire in 2003.

There was no apportionment in the first quarter of 2005, but pressure restrictions continue to limit capacity on Cochin. Apportionment is anticipated to occur between June and September 2005 due to a scheduled line shut-down for hydro-testing.

Cochin Apportionment

	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05
Apportionment	32%	0%	0%	5%	0%	0%	5%	0%
Throughput (10 ³ m ³ /d)	7.4	11.4	11.0	10.3	12.3	8.7	7.6	9.4

Wascana Pipeline

As operator of the Wascana Pipeline, PMC (Nova Scotia) Company received notice that the Bridger Pipeline would not be able to accept deliveries of crude oil from Wascana south of the first Bridger Pipeline pump station at Poplar, Montana because of integrity concerns. As a result of this constraint on the U.S. side, Wascana has been operating at greatly reduced rates. The Bridger Pipeline is currently investigating and repairing a large number of anomalies that were identified on its system. While it is still too early to determine with any certainty when the Bridger Pipeline will return to normal operation, the company's target is the end of August 2005.

2.2 Index of Pipeline Tolls

Another indicator of the efficiency of the transportation system is whether pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices. The Board assesses this by analyzing the change over time in a benchmark toll for each major pipeline (e.g., TransCanada's Eastern Zone toll or Westcoast's T-South export toll). Given the nature of cost of service regulation, pipeline tolls may increase simply because a major capital project was undertaken to meet shippers' needs. Nonetheless, if a benchmark toll increases sharply, it could indicate an issue in transportation markets (e.g., falling throughput or contract demand).

Gas Pipelines

Figure 10 compares the tolls for TransCanada, Westcoast and Foothills Pipe Lines Ltd. (Foothills) with the Implicit Price Index (IPI), Non-residential structures³, normalized to the year 1997.

The increase in TransCanada's Eastern Zone toll between 1997 and 2001 is mainly attributed to the large amount of decontracting on the Mainline during that period, particularly after the startup of the Alliance pipeline in 2000. The toll has been tracking the IPI fairly closely since 2001.

In 2000, Westcoast's T-South export toll increased over 10 percent from the previous year primarily because of non-routine pipeline integrity costs. The export toll began moving more closely to the IPI in 2001.

After declining in 1999 as a result of a cost-effective expansion of its system, Foothills' Zone 9 tolls have remained fairly stable. In addition, Maritimes & Northeast Pipeline's (M&NP) tolls have been relatively constant at around \$0.66-68/GJ since it began operations in 2000 and Alliance's tolls have remained flat at \$0.77/GJ since it began operations in 2001.

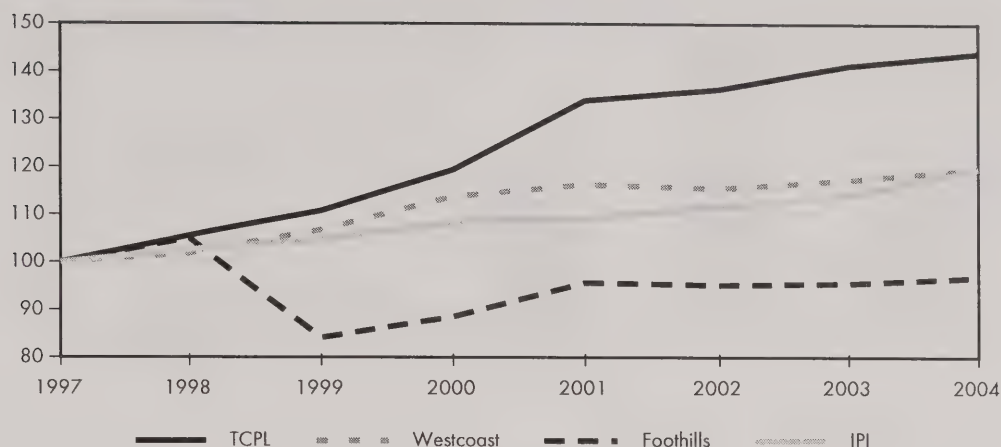
3 Statistics Canada suggested this index as being a suitable index for pipeline services.

Statistics Canada - CANSIM Series v3840577 - Table 384-0036: Implicit price indexes, Gross Domestic Product (GDP), PEA; Canada; Business gross fixed capital formation, non-residential structures (Index, 1997=100)

FIGURE 10

Gas Pipeline Tolls and the Implicit Price Index (Normalized to the Year 1997)

Normalized Value



Oil Pipelines

Figure 11 below shows benchmark tolls for Enbridge, Terasen (TMPL) and Trans-Northern Pipelines Inc. (TNPI) compared with the IPI, Non-residential structures, normalized to the year 1997.

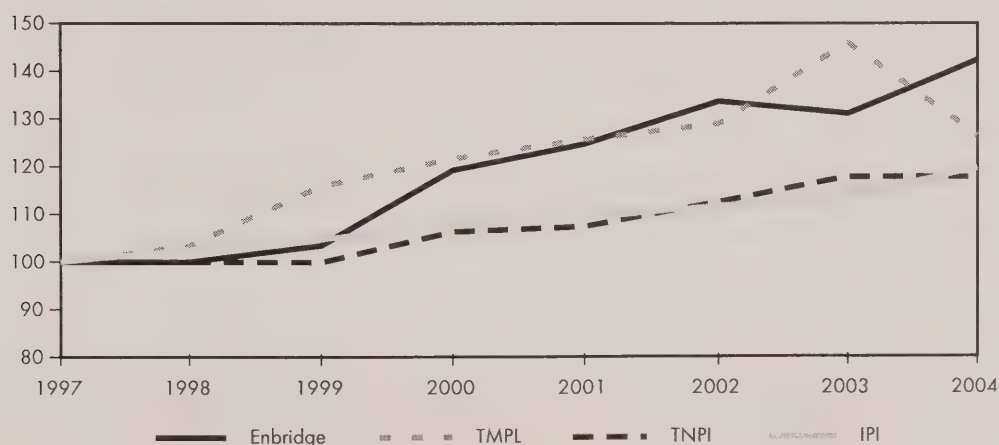
In 2000, Enbridge's tolls (Edmonton to International border) increased because throughput levels were unexpectedly low in 1999. Under its negotiated settlement, Enbridge was able to recapture the shortfall in the ensuing years. The increase in 2004 tolls was mainly because Enbridge was operating at approximately 80 percent capacity utilization, as throughput has not filled recent capacity expansions. The full fixed costs are spread across lower volumes, resulting in higher tolls.

In 1999, Terasen (TMPL)'s tolls (Edmonton to Burnaby) increased because of low forecasted throughput (the 1999 forecast was 17.9 percent lower than the 1998 forecast and the toll is calculated based on forecast throughput). In 2004, Terasen (TMPL)'s tolls decreased, mainly because of the

FIGURE 11

Oil Pipeline Tolls and the Implicit Price Index (Normalized to the Year 1997)

Normalized Value



disposition of 2003 deferrals for higher revenue and lower costs and slightly higher throughput starting in October 2004.

TNPI's tolls (Oakville to Montreal) have generally moved in tandem with the IPI since 1997.

2.3 Shipper Satisfaction

Shipper satisfaction is also another key measure of the efficiency of the transportation system. The Board uses the following tools to measure shipper satisfaction with the services they receive from pipeline companies:

- an annual survey;
- feedback through informal discussions with shippers and other stakeholders; and
- formal complaints filed with the Board.

2.3.1 NEB Pipeline Services Survey

In June 2004, the Board established an annual Pipeline Services Survey to obtain direct feedback from the shippers of ten major NEB-regulated pipeline companies on the level of service provided by those companies. The survey was also used to obtain feedback on the Board's performance in implementing its regulatory role with respect to tolls and tariffs.

In January 2005, the first Pipeline Services Survey was administered. Companies sent the survey to each of their active shippers, who then returned their responses directly to the Board. The overall response rate to the survey was 23 percent.

After analyzing the survey responses, the Board published a summary of the results in aggregate. The aggregate results include the industry average and distribution of responses for each question and a summary of any major themes or trends. In addition, the Board provided each pipeline and those shippers that participated in the survey with detailed company-specific results. Those results included the pipeline company's average rating and distribution of responses for each question and the verbatim comments received from shippers, with the source of those comments removed.

Figure 12 shows the aggregate results for the first survey question, which asked shippers to rate the overall quality of service provided over the last year (1 indicates "very dissatisfied" and 5 indicates "very satisfied"). The figure shows that shippers, on average, are reasonably satisfied with the services provided by pipeline companies⁴.

The survey results indicated that shippers believe the pipeline companies are doing well in the following areas:

- physical reliability of operations;
- timeliness and accuracy of invoices and statements; and
- timeliness and usefulness of operations information.

The areas where shippers believe that pipeline companies could improve the most are:

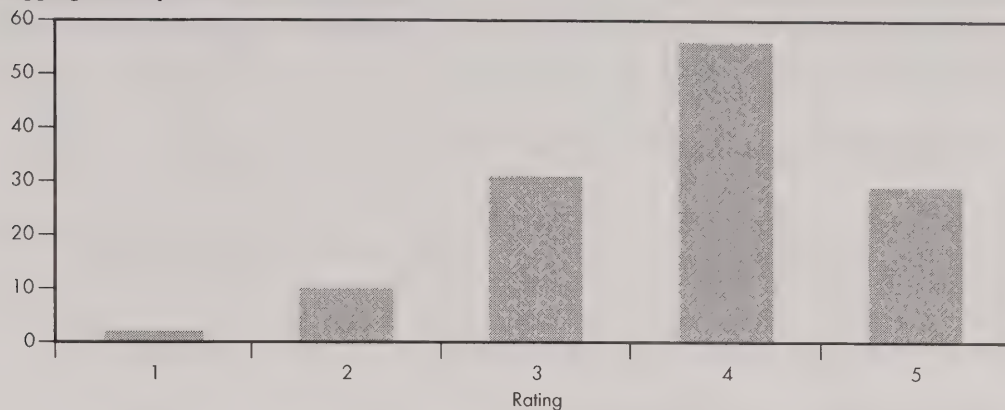
- make tolls more competitive;

⁴ The industry average is the average of all responses across all pipelines.

FIGURE 13

Overall Quality of Service (Industry Average, 3.78)

Aggregate Responses



- exhibit an attitude of continuous improvement and innovation; and
- work towards fair and reasonable solutions when resolving issues.

Appendix 2 provides the aggregate scores on all survey questions. For the complete report on the aggregate results, go to www.neb-one.gc.ca/Publications/ and look under Survey Results.

2.3.2 Informal Monitoring

Informal monitoring involves face-to-face discussions between NEB staff and pipeline companies, shippers, provincial regulators and other stakeholders, such as members of the investment community. It enables NEB staff to seek views on industry issues and concerns, including pipeline performance and perceptions about regulatory processes. These discussions also provide the Board with an opportunity to gauge the efficiency of transportation systems and can provide an early signal of the need for leadership in some areas of economic regulation⁵.

Some examples of comments received from stakeholders during informal monitoring meetings included:

- Where possible, tolls should be set for multiple years (e.g., three to five years) at a time. This practice would provide cost savings, more toll certainty and avoid re-examining the same material over and over. Some shippers stated that an NEB policy statement would encourage this outcome (similar to what the Federal Energy Regulatory Commission does with its *Notice of Proposed Rulemakings*). This suggestion was supported by a number of members of the investment community.
- A mechanism is needed for the Board to hear shipper concerns on a regular basis. With negotiated settlements, shippers feel that the Board gets little information on their concerns.

⁵ The Board is, of course, bound by its Code of conduct not to discuss any matter with outside parties that is currently a matter before the Board in a regulatory proceeding. See the Board's Web site for a copy of the Code of conduct.

2.3.3 Formal Complaints

The number and nature of formal shipper complaints to the Board is another indicator of how satisfied shippers are with pipeline services. A sizeable number of complaints could indicate that a problem needs to be addressed. There have only been a few complaints filed in the last two years that have required a formal process before the Board.

2.4 Pipeline Financial Viability and Ability to Raise Capital

The final measure of the efficiency of the transportation system is the financial strength of the pipeline companies. This section looks at the financial viability of several NEB-regulated pipeline companies and their ability to raise capital on reasonable terms and conditions to invest in infrastructure. To undertake this assessment, the following factors are examined: financial ratios, credit rating reports and equity analyst assessments.

As noted in the Introduction, it is not the intention of this report to assess factors that would be examined in a regulatory proceeding on cost of capital such as the comparable earnings standard or the capital attraction standard. Rather, the purpose of this report is to provide a broad assessment as to whether the Canadian transportation system is working and one factor in that regard is whether it is able to efficiently expand to meet the needs of producers and end-use customers.

2.4.1 Financial Ratios

Financial ratios are useful indicators of a company's performance and financial situation. They can be used to evaluate a company's liquidity, operating performance, growth potential and risk. Evaluating financial ratios is most meaningful when the ratios for a particular company are tracked over time or compared with industry benchmarks. Care must always be exercised in collecting and interpreting financial ratios for pipeline companies given that some financial information pertains to their larger parent companies which may include non-regulated assets.

Some key ratios used to assess the financial viability of pipeline companies include interest coverage ratios, funds from operations to total debt, return on equity (ROE) and total debt to equity. A few of these ratios are discussed below.

Interest Coverage Ratios

Interest coverage ratios measure how many times interest payments could be made with a company's earnings before interest expenses and income taxes are paid. From a bondholder's perspective, interest coverage is an indicator of whether a company could have problems making its interest payments. From an equity holder's perspective, this ratio helps to give some indication of the short-term financial viability of the company.

One formula used to determine the coverage of interest is Earnings Before Interest and Taxes (EBIT) divided by Annual Interest Expense. Another coverage ratio that focuses on cash flows rather than accounting income is funds from operations (FFO) interest coverage. FFO interest coverage data are not included in this report.

A higher coverage ratio is typically better for both bondholders and equity investors. From a bondholder's perspective, a high coverage ratio indicates a low probability that the firm will fail to

meet its interest obligations in the near term. For stock investors, a high ratio indicates that a company is relatively solvent.

- Table 4 shows the EBIT interest coverage ratios for Group 1 pipeline companies as calculated by the Dominion Bond Rating Service (DBRS). Most interest coverage ratios are in the 2-3 times range, except for Terasen (TMPL) which has a coverage ratio many times higher than its peers. The reason for this higher ratio is primarily because of Terasen (TMPL)'s common equity ratio of 45 percent, which means it carries less debt. Table 4 also shows that the coverage ratios for most companies are stable or improving over time.

DBRS notes that interest coverage ratios for Canadian pipelines are often lower by 1.0 to 1.25 times than those for U.S. pipelines. It cites the following factors as contributing to these lower coverage ratios:

- lower allowed returns on equity (typically 200 basis points);
- lower allowed deemed common equity ratios of 30 percent to 35 percent in Canada; and
- flow-through tax accounting in Canada versus the normalized method in the U.S. (which allows for the recovery of deferred income taxes in tolls).

Despite the lower coverage ratios as noted by DBRS, none of the major NEB-regulated companies has had a problem servicing their debt obligations.

Return on Equity

Return on Equity (ROE) is a common measure of financial performance and is frequently used when evaluating and comparing companies. The ROE a company earns can be expressed financially as net income divided by common equity. However, for NEB-regulated pipeline companies, this ratio is expressed as the return on the equity portion of the rate base that is approved by the Board.

Table 5 shows the actual ROE for several Group 1 pipeline companies from 1999 to 2004 along with the NEB-approved ROE in accordance with the RH-2-94 Formula⁶. Alliance, Enbridge, M&NP and Terasen (TMPL) are not subject to the NEB-approved ROE as they all have negotiated a different

TABLE 4

EBIT Interest Coverage Ratios

	2000	2001	2002	2003
Alliance	-	1.85	1.92	1.85
Enbridge	2.80	2.84	3.02	-
Foothills	2.16	2.16	2.39	2.41
M&NP	1.55	1.82	2.05	-
Terasen (TMPL)	3.62	4.69	6.12	7.03
TQM	1.99	2.15	2.36	2.36
TransCanada	1.97	2.16	2.32	2.36
Westcoast	1.58	1.99	2.14	1.85

⁶ Formula used to determine the rate of return on common equity for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, as amended to eliminate rounding.

TABLE 5

Return on Equity for the Period 1999 to 2004

	1999	2000	2001	2002	2003	2004
Alliance	-	11.21	11.25	11.25	11.25	-
Enbridge	11.70	11.20	12.20	13.00	-	-
Foothills	9.58	9.90	9.61	9.53	9.79	9.56
M&NP	-	13.80	14.20	12.95	12.31	13.75
Terasen (TMPL)	18.50	17.50	19.60	20.40	20.40	-
TQM	9.94	9.96	10.21	9.80	10.21	9.84
TransCanada	9.64	9.99	9.72	9.95	10.18	10.18
TCPL B.C. System	9.58	9.90	6.86	9.53	8.21	8.51
Westcoast Field Services	-	-	13.62	14.87	6.76	11.63
Westcoast Transmission	11.68	12.68	15.84	13.44	12.93	10.28
NEB RH-2-94 Formula	9.58	9.90	9.61	9.53	9.79	9.56

Source: DBRS (Enbridge, Terasen); NEB Surveillance and Annual Reports (all others); dash indicates not available

ROE with their shippers⁷. Also, Westcoast's Field Services Division is not subject to the formula as its tolls for gathering and processing services are negotiated individually with shippers.

The ROE numbers for Enbridge and Terasen (TMPL) have been taken from their DBRS Credit Rating reports as those companies currently do not file NEB surveillance reports. As such, the numbers are somewhat higher than one would normally expect and might include some non-regulated income in the calculations (e.g., Terasen (TMPL)'s income includes \$6 to \$7 million annually of dividend income from its parent, Terasen Inc.). The complete details of these credit rating reports should be read before comparing the ROE for Enbridge and Terasen to the other companies listed in Table 5.

2.4.2 Credit Ratings

In Canada, credit ratings are determined by three independent credit rating agencies, DBRS, Moody's and Standard & Poor's (S&P). See Appendix 1 for a comparison of the rating scales for DBRS and S&P. Credit ratings, like stock prices, generally reflect the consolidated operations of the entire company and not solely the regulated portion. Thus, the use of credit ratings as an accurate measure of the performance for a regulated pipeline owned by a company that has both regulated and non-regulated operations, such as TransCanada and Enbridge, has to be interpreted with some care. In addition, credit ratings are somewhat subjective in that the rating imposed on a company is the expert opinion of an investment analyst, which may result in different ratings by different firms.

DBRS

In assigning a credit rating to a particular company, DBRS attempts to consider all meaningful factors that could impact the risk of maintaining timely payments of interest and principal in the future. While the key considerations will vary industry by industry, some of the common factors that are considered for most ratings are: core profitability; asset quality; strategy and management strength; and financial and business risk profile.

⁷ Negotiated ROE for Alliance is 11.25 percent and for M&NP is 13.0 percent.

For pipelines, electric and gas utilities, the following factors are also important considerations in deriving the credit ratings: regulatory factors, competitive environment, supply and demand considerations, and regulated vs. non-regulated activities.

The credit ratings for the Group 1 pipeline companies shown in Table 6 indicate that the ratings have remained stable from 1999 to the present. Alliance has improved from BBB(high) to A(low).

Standard & Poor's

An S&P credit rating is a current opinion of a company's overall financial capacity to pay its financial obligations. S&P bases its ratings on the overall creditworthiness of the corporation. Therefore, the rating of a wholly-owned subsidiary company, in the absence of meaningful ring-fencing measures, generally reflects the creditworthiness of the parent. This opinion focuses on the company's capacity and willingness to meet its financial commitments as they come due and may also apply to specific financial obligations. The rating histories for several Group 1 pipeline companies are provided in Table 7.

In S&P's rating methodology, a company rated 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than companies in higher-rated categories. A company rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the company to meet its financial commitments.

TABLE 6
DBRS Credit Rating History – Senior and Subordinated Debt

	1999	2000	2001	2002	Current
Alliance	BBB(high)	BBB(high)	A(low)	A(low)	A(low)
Enbridge	A(high)	A(high)	A(high)	A(high)	A(high)
M&NP	A	A	A	A	A
Terasen (TMPL)	A(low)	A(low)	A(low)	A(low)	A(low)
TQM	A(low)	A(low)	A(low)	A(low)	A(low)
TransCanada	A	A	A	A	A
Westcoast	A(low)	A(low)	A(low)	A(low)	A(low)

TABLE 7
S&P Credit Rating History

	2000	2001	2002	2003	2004
Enbridge	A-/Stable	A-/Negative	A-/Negative	A-/Stable	A-/Stable
Terasen (TMPL)	BBB+/Stable	BBB+/Stable	BBB+/Watch Neg	BBB/Stable	BBB/Stable
TQM	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable
TransCanada	A-/Stable	A-/Stable	A-/ Watch Neg	A-/Negative	A-/Negative
Westcoast	A-/Negative	A-/Stable	A/Negative	BBB/Stable	BBB/Positive

Each of these agencies has expressed an opinion at various times that the ROE awarded through the RH-2-94 Formula and the deemed equity ratios awarded by the Board are low by international standards. Nonetheless, the ratings assigned by the credit rating agencies indicate that NEB-regulated companies are all within investment grade.

2.4.3 Access to Capital Markets

As mentioned in the Introduction, pipeline companies must be able to access capital to expand and maintain their systems to adequately meet the evolving needs of the marketplace.

The most straightforward test of a pipeline company's ability to finance new capacity is market evidence of their ability or inability to finance major new construction. However, there has not been much pipeline construction in the last few years because natural gas production from the Western Canada Sedimentary Basin (WCSB) has hit a plateau and adequate pipeline capacity is in place. While there has been some recent expansion of oil pipeline capacity, no really large investments have been made. Thus, the question to ask is whether or not pipeline companies would have any difficulty in financing new projects when they arise.

To answer this question, the Board met with credit rating agencies, suppliers of capital and equity analysts in the investment community to discuss their views on the ability of Canadian pipelines to access capital markets, their general criteria for assessing NEB-regulated pipelines, and their views on the current regulatory environment in Canada.

On the primary question of access to capital, all of the organizations consulted indicated that Canadian pipelines should have no difficulty raising capital at reasonable cost at this time. For example, they believed that there should be no major challenges in financing a pipeline such as the Mackenzie Valley natural gas pipeline or additional oil pipelines to carry growing production from the oil sands. It was noted by some that debt issues for Canadian pipelines have traditionally been very attractive, in part because of the secure regulatory environment. The organizations consulted were generally of the view that a debt issue would be favourably received by the market.

With respect to attracting equity, some investment analysts noted that a major equity issue at the current ROE awarded by the NEB could be more problematic. They noted that recent projects, such as Alliance and M&NP, have been based on a higher equity return. It was noted by some that incumbent pipelines are at a disadvantage if they have to raise capital at the existing ROE. Others were of the view that greenfield projects are riskier and simply require a higher ROE to attract the equity investment. It was recognized that the Board has approved the higher ROEs that have been necessary to support greenfield pipelines such as Alliance and M&NP.

2.4.4 Other Comments by the Investment Community

Credit rating agencies and pension funds are primarily concerned about the predictability of cash flows to support debt and dividend payments. In this regard, the Board's RH-2-94 Formula is viewed positively because it improves predictability. Most of the companies with whom the Board met stated that they would like to see arrangements that provide certainty over multi-year periods because annual toll hearings introduce uncertainty and can distract pipeline management from focusing on other important aspects of their business. They also would like to see tolls and tariffs in place at the start of a fiscal year because interim toll situations increase uncertainty.

Pension fund administrators expressed the view that the Board should ‘protect’ credit ratings because downgrades could be very costly to bondholders. They noted that Canadian bonds are an important revenue source for Canadian pension funds and that a downgrade could require them to sell a large percentage of their bonds at discounted prices. On the other hand, some groups were of the view that the Board should not be overly concerned about maintaining a ‘target’ credit rating for a pipeline; investment grade ratings should be adequate.

It was noted by some that the business environment for the traditional Canadian gas pipelines has become somewhat riskier since the construction of the Alliance pipeline and the slowdown in the growth of gas production. Accordingly, they believe that basic financial parameters in the Board’s regulatory scheme should be improved⁸. Finally, a number of parties expressed concern that the Board does not have adequate rules to ensure financial protection (‘ring-fencing’) of a regulated utility and concern was expressed that cash could be drained from a pipeline company if its parent were to experience severe financial difficulties.

2.4.5 Assessments by Equity Analysts

Several equity analysts regularly publish their assessments of various companies for investors. The Board reviews these assessments for the consolidated operations of pipeline companies as they provide some useful information on their financial viability and outlook for the future. As with credit ratings, equity analysts generally focus on companies that have stand-alone share offerings and, in many cases, these offerings include non-regulated as well as regulated businesses. While observations vary from analyst to analyst and from company to company, most NEB-regulated pipelines have been rated in the ‘hold’ or ‘buy’ categories over the last year, indicating that this sector of the investment community does not have any significant concerns about their short-term prospects.

⁸ In its RH-2-2004 Phase II Reasons for Decision dated April 2005, the Board approved an increase in TransCanada’s deemed common equity ratio from 33 percent to 36 percent.

CONCLUSIONS AND EMERGING ISSUES

Conclusions

Based on the chosen measures, the Board believes that the Canadian hydrocarbon transportation system is working very well at the present time.

Currently, **there appears to be adequate natural gas pipeline capacity in place on existing systems**, especially since production from the WCSB has levelled off over the last few years. The existence of some excess capacity out of the WCSB has provided producers with the flexibility to access their market of choice and the value of natural gas exports hit a record high of \$26.5 billion in 2004. There are some constraints in the system east of Dawn, Ontario but this has not to date caused any prolonged problems in delivering adequate volumes to the marketplace to meet the needs of consumers.

Overall, there is adequate capacity on the oil pipeline transportation system and all types of oil produced in the WCSB are being delivered to markets within and outside Canada. However, capacity on some systems has been tight, notably on Terasen (TMPL). This has been illustrated by the need for Terasen (TMPL) to apportion shippers in recent months and by Chevron's request for priority destination status for its Burnaby refinery. Canadian oil producers also appear to believe that there is a need to improve access to heavy crude oil markets in the U.S. Inadequate access to refineries designed to run heavier crudes appears to have been a contributing factor to the recent high heavy/light price differentials for Canadian crudes. This need for improved access has been illustrated by the Canadian industry's support for the reversal of two U.S. pipelines to Cushing, Oklahoma and the U.S. Gulf Coast to allow growing oil sands production to penetrate new markets.

Based on the results from the NEB Pipeline Services Survey, **shippers are reasonably satisfied with the services provided by pipelines** (overall rating of 3.78 out of 5). In particular, physical reliability of pipeline operations was rated very highly by shippers, indicating that products are reliably delivered to markets. There are, however, a few areas where some work is required on the part of the pipeline companies to improve service, including:

- making tolls more competitive;
- exhibiting an attitude of continuous improvement and innovation; and
- working collaboratively towards fair and reasonable solutions to resolve issues.

The financial assessment indicates that **NEB-regulated pipeline companies are financially sound**. However, it is recognized that some of the data and indicators reviewed are for the consolidated operations of pipeline companies. While pipeline companies have not had to raise large amounts of capital in recent years, the Board's survey of the investment community revealed that it believes that

pipeline companies should have no difficulty in raising capital to finance most major new projects at this time.

The Board recognizes that this report is a snapshot in time and does not include a comparison, for example, with pipelines in other jurisdictions. The Board considers this report as a first step in assessing the effectiveness of the hydrocarbon transportation system in Canada. The Board will continue to monitor the effectiveness of the system and will continue to meet with parties to gain an understanding of all perspectives on the transportation system. The Board welcomes feedback at any time on the measures and conclusions in this report and welcomes suggestions for improvements to future reports.

Emerging Issues

While the transportation system is currently working well, there are a number of emerging challenges facing the industry.

To meet the needs of producers and users, the transportation system must be able to adapt to the changing needs of the market over time and expand to attach new sources of supply. This can be particularly challenging for the pipeline sector because investments tend to be “lumpy” and, given the long life of the assets, investors have to be reasonably assured of the existence of supply and markets over a long time period. Clearly, the longer the time period over which an investment is recovered, the greater the possibility that market circumstances will change.

The potential for market change over time is highlighted by the uncertainties around the number of liquefied natural gas (LNG) terminals that will be built in North America and the potential effects that imported LNG will have on the supply and demand balance and on the pattern of natural gas flows. For example, the construction of LNG terminals in Quebec could have important implications for the flow pattern on TransCanada and TQM and could impact the toll design of the system.

Another event that could impact the supply and demand balance and consequent gas flows is the significant potential gas requirement for power generation that will be driven by Ontario’s policy to remove 7 500 MW of coal-fired capacity from its system. Although the refurbishment of existing nuclear generation might meet part of the requirement for the displaced coal, there will likely be a significant volume of new natural gas-fired generation to enter the system. The exact impact of this incremental generation on natural gas pipelines will depend on the total amount of generation awarded and the location.

On the oil side of the market, the expected growth in production from the oil sands is posing tough choices for the industry regarding which incremental markets to access and how to expand the pipeline system. Options include expansion of existing systems and construction of new systems to access new markets in either or both the U.S. and Asia. Given the large capital outlay and the relative irreversibility of the investment decision, market participants want to ensure that the optimal decisions will be made.

From a regulatory perspective, the challenge is to provide a fair and effective process that does not distort the investment decisions that should optimally be made in the marketplace. Investors in new pipelines desire clear regulatory processes with predictable timelines. New investment can be frustrated when timelines stretch out and unexpected regulatory hurdles materialize during the process. Unnecessary delays in construction of new systems that are in the public interest can result in increased costs to energy users as development of new supplies are constrained.

The flattening of natural gas production from the WCSB and construction of the Alliance pipeline has created challenges for a number of the older systems that are experiencing a sharp decline in the long-term contracts on their systems. Natural gas is still being moved on these systems, but many shippers prefer to rely on short-term services to maximize their flexibility. Under the traditional cost of service approach, the remaining firm shippers have to bear the load of recovering the fixed costs in the form of rising tolls. While the erosion of long-term contracts has not yet vitiated the cost of service framework, new toll design structures may need to be considered to effect a fair sharing of costs and to maintain the competitiveness of these systems.

Lastly, having regard to the financial viability of the pipeline companies, there is interest in the investment community and amongst shippers in working towards multi-year frameworks for the establishment of tolls on more pipeline systems. A multi-year framework would provide more certainty for all parties and reduce the burden associated with continual negotiations and regulatory proceedings. While the Board is committed to working towards a framework which reduces regulatory uncertainty, it recognizes that it may be difficult to structure a multi-year framework that will meet the needs of all parties when the market context is expected to change considerably in the next few years. The investment community would also like to see tighter regulatory rules regarding parent-affiliate dealings in order to protect the cash flows of the regulated entities.

Some of these issues will be settled amongst parties, others may be examined in formal proceedings before the Board, and others may be amenable to potential regulatory actions outside of the hearing process. The Board will continue to consult with stakeholders on these issues and seek input if and when any regulatory initiatives are pursued.

DEBT RATING COMPARISON CHART

This chart provides a comparison of the rating scales used by DBRS and S&P when rating long-term debt.

Credit Quality	DBRS	S&P
Superior	AAA	AAA
	AA high	AA+
	AA	AA
	AA low	AA-
Good	A high	A+
	A	A
	A low	A-
Adequate	BBB high	BBB+
	BBB	BBB
	BBB low	BBB-
Speculative	BB high	BB+
	BB	BB
	BB low	BB-
Highly Speculative	B high	B+
	B	B
	B low	B-
	CCC	CCC
	CC	CC

Ratings in the Adequate category and above are considered Investment Grade.

Standard & Poor's also provides a Rating Outlook that assesses the potential direction of a long-term credit rating over the intermediate to longer term. A 'Positive' outlook means that a rating may be raised; a 'Negative' outlook means that a rating may be lowered; and a 'Stable' outlook means that a rating is not likely to change.

PIPELINE SERVICES SURVEY AGGREGATE RESULTS

The results below are the aggregate responses from shippers on several major NEB-regulated pipeline companies. See the Board's Web site for the complete details.

1. How satisfied are you with the OVERALL quality of service provided by the pipeline company over the last calendar year?

1	2	3	4	5	Average
2	10	31	56	29	3.78

2. What are the things that this pipeline company does well?
3. What are the things that this pipeline company could do better?
4. How satisfied are you with the physical reliability of the pipeline company's operations?

1	2	3	4	5	Average
2	9	12	53	52	4.13

5. How satisfied are you with the quality, flexibility and reliability of the pipeline company's transactional systems (nominations, bulletin boards, reporting, contracting, etc.)?

1	2	3	4	5	Average
5	9	32	51	27	3.69

6. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?

1	2	3	4	5	Average
3	9	19	49	38	3.93

7. How satisfied are you with the timeliness and usefulness of *operations* information (outages, available capacity, scheduled maintenance, flows, etc.) provided by the pipeline company?

1	2	3	4	5	Average
5	9	24	61	26	3.75

8. How satisfied are you with the timeliness and usefulness of *commercial* information (tolls, service changes, new services, contract information, etc) provided by the pipeline company?

1	2	3	4	5	Average
1	11	34	65	16	3.66

9. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?

1	2	3	4	5	Average
8	21	46	38	11	3.19

10. How satisfied are you with the accessibility and responsiveness of the pipeline company to shipper issues and requests?

1	2	3	4	5	Average
6	19	28	51	18	3.46

11. How satisfied are you that the pipeline company works towards fair and reasonable solutions when resolving issues?

1	2	3	4	5	Average
6	24	32	42	12	3.26

12. How satisfied are you with the suite of service options (FT, IT, backhaul, etc.) offered by the pipeline company?

1	2	3	4	5	Average
3	6	33	47	15	3.63

13. How satisfied are you that this pipeline company's transportation tolls are competitive?

1	2	3	4	5	Average
9	14	55	39	4	3.12

14. How satisfied are you with the collaborative processes (negotiations or task force meetings) utilized by this pipeline company?

1	2	3	4	5	Average
6	8	47	45	7	3.35

15. How satisfied are you that the current negotiated settlement agreement or tariff arrangements work well to provide fair outcomes?

1	2	3	4	5	Average
7	9	43	49	9	3.38

-
16. How satisfied are you that the NEB has established an appropriate regulatory framework in which negotiated settlements for tolls and tariffs can be reached?

1	2	3	4	5	Average
5	7	35	51	16	3.58

17. When toll and tariff matters are not resolved through settlement, how satisfied are you with the Board's processes to resolve disputes?

1	2	3	4	5	Average
4	11	33	38	13	3.46

18. What could the Board be doing to improve its processes through which tolls and tariffs are determined?
19. Additional comments

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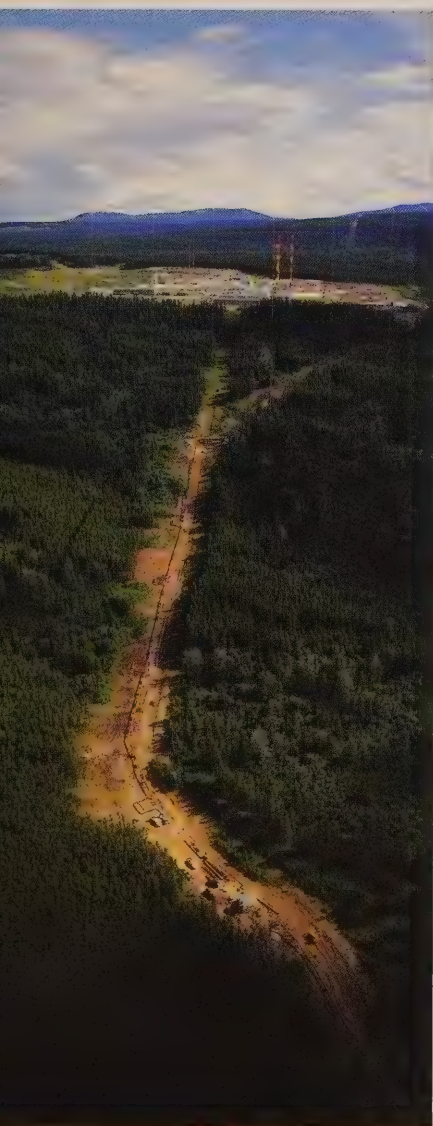


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CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT



JUNE 2006

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CANADIAN HYDROCARBON

TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT

JUNE 2006

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ACRONYMS AND ABBREVIATIONS

AOS	Authorized Overrun Service
Alliance	Alliance Pipeline Ltd.
Altex	Altex Energy Ltd.
CAPP	Canadian Association of Petroleum Producers
CEPA	Canadian Energy Pipeline Association
Cochin	Cochin Pipe Lines Ltd.
Coral	Coral Energy Canada Inc.
DBRS	Dominion Bond Rating Service
EBIT	Earnings Before Interest and Taxes
Enbridge	Enbridge Pipelines Inc.
Express	Express Pipeline Limited Partnership
Foothills	Foothills Pipe Lines Ltd.
FT	Firm Transportation
FT-RAM	Firm Transportation Risk Alleviation Mechanism
GDP	Gross Domestic Product
Gateway	Gateway Pipeline Inc.
IGUA	Industrial Gas Users Association
Irving/Repsol	Irving Oil Company Limited and Repsol YPF
Kinder Morgan	Kinder Morgan Canada Inc.
LNG	Liquefied natural gas
M&NP	Maritimes & Northeast Pipeline Management Ltd.
Mackenzie	Mackenzie Gas Project

Moody's	Moody's Canada Inc.
NEB or Board	National Energy Board
OEB	Ontario Energy Board
PADD	Petroleum Administration Defense Districts
PCOG	Petro-Canada Oil and Gas
PNGTS	Portland Natural Gas Transmission System
ROE	Return on Common Equity
S&P	Standard & Poor's
Terasen	Terasen Pipelines Inc.
T-South	Westcoast's Southern Mainline (Zone 4)
TNPI or Trans-Northern	Trans-Northern Pipeline Inc.
TPTM	Terasen Pipelines (Trans Mountain) Inc.
TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada or TCPL	TransCanada PipeLines Limited
U.S.	United States
Union Gas	Union Gas Limited
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission

UNITS

Bcf	Billion cubic feet
MMcf/d	Million cubic feet per day
GJ	Gigajoule
m ³ /d	Cubic metres per day
10 ³ m ³ /d	Thousand cubic metres per day
MW	Megawatt

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency whose purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest¹ within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The NEB is an active, effective and knowledgeable partner in the responsible development of Canada's energy sector for the benefit of Canadians.

The main functions of the NEB include regulating the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs. Another key role is to regulate international power lines and designated interprovincial power lines. The NEB also regulates natural gas imports and exports, oil, natural gas liquids (NGLs) and electricity exports, and some oil and gas exploration on frontier lands, particularly in Canada's North and certain offshore areas. In addition, the Board provides energy information and advice by collecting and analyzing information about Canadian energy markets through regulatory processes and monitoring.

This report, the second of its kind, provides an assessment of the Canadian hydrocarbon transportation system. To do so, it brings together data from various publicly available sources that was collected and monitored by NEB staff as well as throughput data supplied by the pipeline companies. The Board also benefited from discussion with members of the investment community with respect to capital markets and emerging issues. Prior to the release of this report, a draft was sent to the Canadian Energy Pipeline Association (CEPA) and the Canadian Association of Petroleum Producers (CAPP) for comment. Comments provided by CAPP and CEPA were taken into consideration in the preparation of this report.

Any comments on the report or suggestions for further analysis can be directed to:

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If a party wishes to rely on material from this report in any regulatory proceeding, it can submit the material as can be done with any public document. In such a case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

Information about the NEB, including its publications, can be found by accessing the Board's website: <http://www.neb-one.gc.ca>.

¹ The Canadian public interest is all Canadians and refers to a balance of economic, environmental and social interests that change as society's values and preferences change.

INTRODUCTION

Energy is essential to our daily lives. The ability of the pipeline transportation system to deliver this energy in the form of natural gas, natural gas liquids (NGLs), crude oil and petroleum products is critical to Canada's economic well-being.

Canadians depend on a safe, reliable and efficient energy supply. The 45 000 kilometres (km) of interprovincial and international pipelines regulated by the NEB are a crucial element in Canada's transportation and distribution system (Figures 1 and 2). These systems include large-diameter, cross-country, high-pressure natural gas pipelines, low-pressure crude oil and oil products pipelines, and small-diameter pipelines.

Pipelines have a well-deserved reputation as the safest and most energy-efficient method of moving vast amounts of fuel from producers to consumers. In 2005, approximately \$120 billion worth of products flowed through Canadian pipelines to markets at home and in the U.S. The cost in 2005 of providing these transportation services is estimated to be around \$5 billion, not including fuel costs paid by shippers on natural gas pipelines. This was accomplished by infrastructure that is mostly invisible to consumers and that operates with a low rate of failure and minimal environmental impact.

To assist in the delivery of its mandate and to ensure that the Board's regulatory oversight provides value to Canadians, the Board developed five goals:

1. NEB-regulated facilities and activities are safe and secure, and are perceived to be so.
2. NEB-regulated facilities are built and operated in a manner that protects the environment and respects the rights of those affected.
3. Canadians benefit from efficient energy infrastructure and markets.
4. The NEB fulfills its mandate with the benefit of effective public engagement.
5. The NEB delivers quality outcomes through innovative leadership and effective processes.

Each year, the Board issues various reports that focus on different aspects of Canadian energy markets. This report, which assesses how well the Canadian hydrocarbon transportation system is working, pertains largely to Goal 3. However, for the system to function efficiently and effectively, it must operate in a safe and environmentally acceptable manner, which relates to Goals 1 and 2. Outcomes related to safety and the environment are discussed in a companion document, the Board's report, *Focus on Safety and Environment, a Comparative Analysis of Pipeline Performance*.

This report should not be read as a regulatory document. In this report, the Board is not making a determination on regulatory matters because the factors on which the functioning of the transportation system is assessed are not necessarily the same as those considered in a regulatory proceeding.

For the hydrocarbon transportation system to work well, the Board believes the following three outcomes should be achieved:

1. there is adequate pipeline capacity in place to move energy products from producers to consumers;
2. pipeline companies are providing services that meet the needs of shippers at reasonable prices; and
3. pipeline companies have adequate financial integrity to attract capital on terms and conditions that enable them to effectively maintain their systems and build new infrastructure to meet the changing needs of the market.

An efficient hydrocarbon transportation system needs to have the ability to be expanded on a timely basis when changing market conditions require new pipeline capacity. In order for expansion to occur in the time frame required, two things should occur. First, pipeline companies must have ready access to financial markets on reasonable terms and conditions. In addition, the regulatory process must be timely and predictable, while allowing a fair opportunity for all affected parties to provide input prior to a decision on an application being made.

In this report, the Board provides an assessment of the ability of pipeline companies to access capital on reasonable terms and conditions. The Board does not, however, provide an assessment of the efficiency and effectiveness of its regulatory processes. The Board reports on a number of regulatory efficiency measures in its *Annual Report to Parliament* and in the annual *Departmental Performance Report* that are submitted to the Treasury Board, both of which are public documents. This report, in the discussion of the Pipeline Services Survey (see Section 2.3.1), does provide information on shippers' perceptions of the Board's regulatory process. The Board recognizes that there is the potential to improve the means by which regulatory effectiveness and efficiency is measured and will be consulting with stakeholders on this topic.

For the Board's financial regulatory purposes, pipeline companies have been divided into two groups, Group 1 and Group 2. Major oil and gas pipeline companies are designated as Group 1 and are actively regulated by the NEB. All other NEB-regulated pipeline companies are classified as Group 2 companies and are subject to a lighter degree of regulation. A listing of companies regulated by the Board, as of 31 December 2005, can be found in Appendix 4.

FIGURE 1

Gas Pipelines Regulated by the NEB

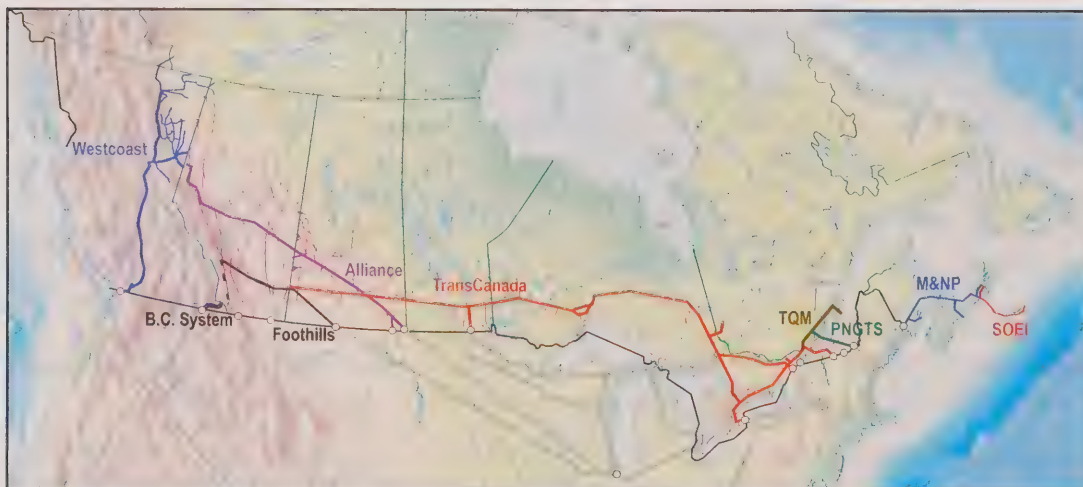
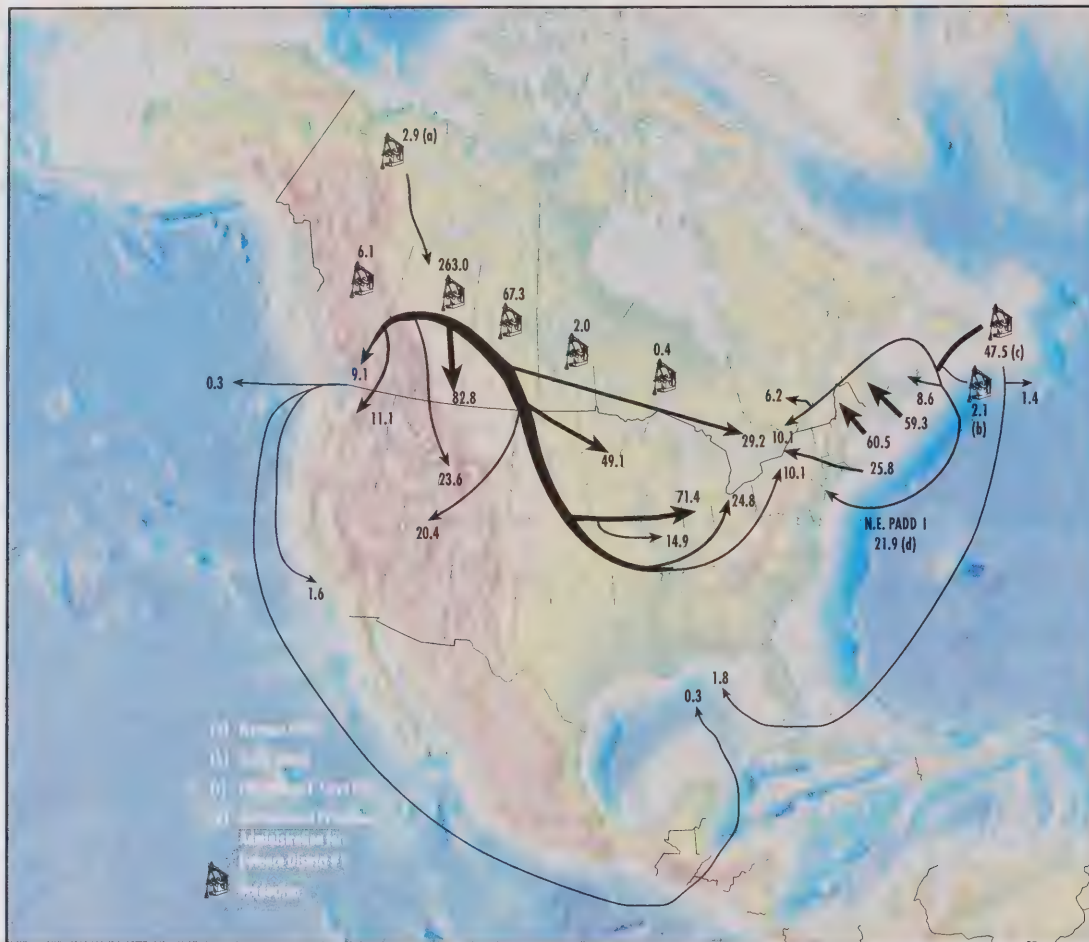


FIGURE 4

2005 Supply and Disposition of Oil



THE CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

2.1 Adequacy of Pipeline Capacity

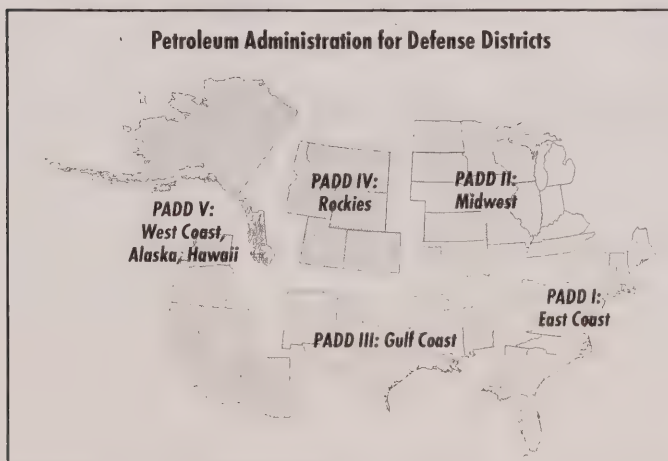
A key measure of an energy market's operational efficiency is the ability of its pipeline system to adequately transport crude oil, refined products, natural gas and NGLs from producing to consuming regions.

This section examines the following factors to assess the current adequacy of pipeline capacity:

1. price differentials compared with firm service tolls for major transportation paths;
2. capacity utilization on pipelines; and
3. the degree of apportionment on major oil pipelines.

The Board has generally taken the view that some excess capacity on a pipeline is better than not having enough. Higher tolls for shippers are a cost of having excess pipeline capacity; however, the costs associated with not having enough pipeline capacity are generally greater. Substantial revenue is lost when producers are unable to move their oil or gas to market. Not only is it important to have some excess capacity, but flexibility with sufficient access to the right markets or for the right type of product is also important.

When there is inadequate pipeline capacity to transport crude oil to the West Coast and PADD V (West Coast) producers have the option of transporting crude oil to Ontario and PADD II (Midwest) or PADD IV (Rockies). In addition, when refineries are in turnaround (maintenance) in Ontario and PADD II, crude oil volumes can be delivered to the West Coast and PADD V or PADD IV providing there is pipeline capacity.



The importance of having adequate pipeline capacity in place is highlighted by the fact that the value of natural gas and oil transported in NEB-regulated pipelines far exceeds the cost of service on those pipelines.

2.1.1 Price Differentials and Natural Gas Firm Service Tolls

When there is adequate pipeline capacity between two market hubs, commodity prices will be connected and the price differential will be equal to, or less than, the transportation costs between the two points. As long as the price differential is less than the toll plus fuel, the market is indicating that there is adequate pipeline capacity between the two pricing points. Conversely, when there is inadequate pipeline capacity between two market points, the basis, that is the differential in price between the two end points, will exceed the cost of transportation. In a market with adequate capacity, sellers would generally direct their product to the market that nets the highest revenue back to the producer, thereby meeting that region's need for energy. Where inadequate capacity exists, the product cannot get to market and the price differential persists, resulting in higher prices for consumers and lost revenues for producers.

In order to use price differentials as a measure of the adequacy of pipeline capacity, there must be reasonably good pricing data available. Two examples of price differentials compared with firm service tolls are provided below – one for transportation on TransCanada PipeLines Limited (TransCanada or TCPL) and one for transportation on Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission (Westcoast).

Figure 5 shows the basis differential between the Alberta border and the Dawn delivery point compared with the TransCanada firm service toll between the two points, including fuel costs. The basis between the Alberta border and the Dawn delivery point is generally below the total cost of transportation (firm transportation plus fuel) via the TransCanada pipeline connecting these two markets. This indicates that pipeline capacity is adequate between these locations. As indicated by the variation in basis between the two locations, natural gas pricing is very responsive to relatively small changes in flow or demand. The short-term increase in the basis differential between September 2005 and January 2006 was a result of increased demand for supply from other basins when gas supplies from the Gulf of Mexico were reduced due to hurricanes Katrina and Rita. Cold weather early in the winter also affected demand. In addition, after the hurricane-induced gas price increase, the cost of fuel for use in the pipeline compressors also increased temporarily. Very mild weather and reduced demand in response to higher prices has since moderated flows and the demand for gas and transportation.

Figure 5: Dawn - Alberta Basis vs. TransCanada Toll and Fuel

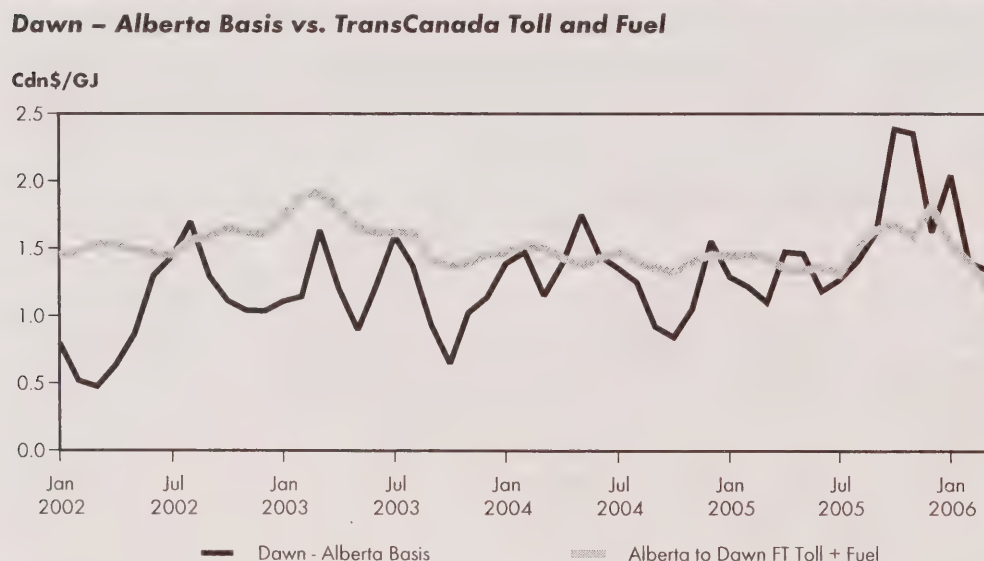
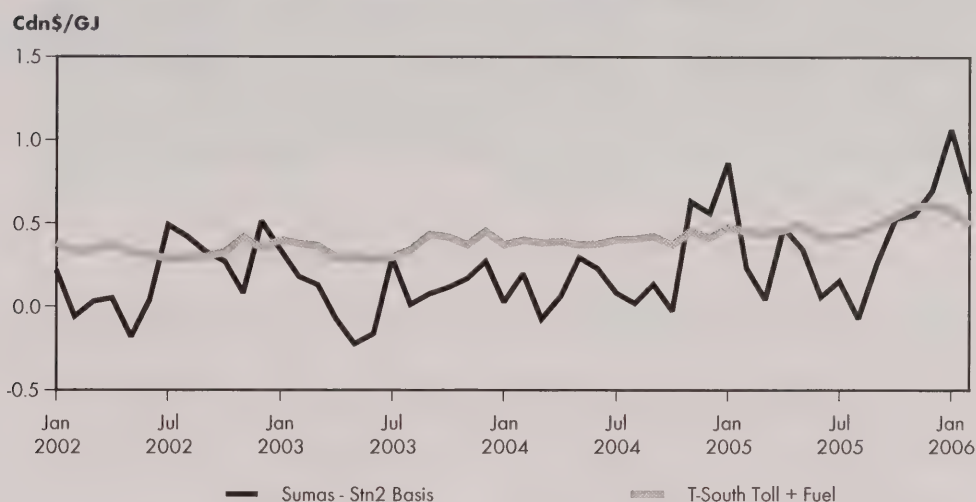


Figure 6 shows the basis between Compressor Station 2 on the Westcoast system and the Sumas export point compared with the Westcoast firm service toll between the two points (T-South or Southern Mainline), including fuel costs. Since January 2002, except for a few months, the basis has been lower than the transportation costs indicating that there has been adequate capacity in place since that time.

FIGURE 6

Sumas – Station 2 Basis vs. Westcoast T-South Toll and Fuel



Note: 2006 - interim term-differentiated toll (5 or more years service).

Overall, the comparison of price differentials and natural gas firm service tolls shows that pipeline capacity between these markets is adequate at most times. In general, the basis between pricing points has been slightly lower than pipeline transportation and fuel costs. However, natural gas pricing is volatile. Hurricane-induced supply disruptions in the Gulf of Mexico and erratic weather impact both basis and pipeline fuel costs. Figures 5 and 6 both indicate times where the basis exceeded transportation and fuel costs. These events proved to be temporary, and gas flows and prices moderated.

Price Differentials and Tolls on Oil Pipelines

The major drivers of price differentials, amongst other things, are availability of pipeline capacity, competition, supply and demand, seasonality and the grade (quality) of crude oil. Price differentials are increasingly becoming an issue on oil pipelines because of the increase in bitumen blend crude oil supply from the oil sands. Limited access to markets, particularly those with refineries that process heavy crude oil, exerts downward pressure on heavy oil prices and widens the light-heavy differential.

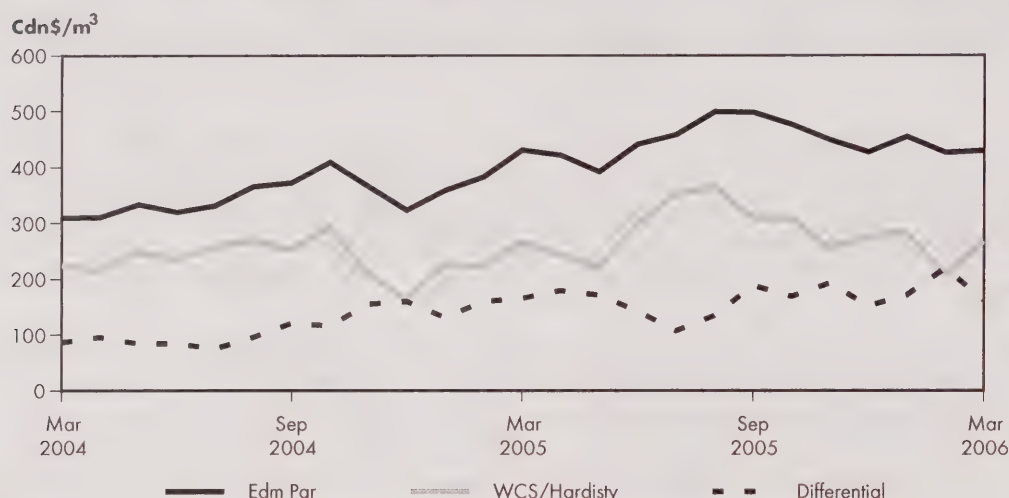
Figure 7 illustrates the wide light-heavy differential as indicated by the difference in price of Edmonton Par light crude oil and Western Canadian Select (WCS), a heavy crude oil. As shown, the average differential has been increasing during the time period shown and in recent years has averaged about 30 percent over the course of a year. Notably, in the first quarter of 2006, the price of heavy crude was, on average, 42 percent less than the price for light crude oil (the light-heavy differential).

Typically, the differential is narrower during the summer months due to the additional demand for heavier crude oil for use in the production of asphalt for paving.

Differentials have also widened as a result of supply growth from the oil sands, pipeline constraints and a lack of refinery capacity to process heavier crude oil. Wide light-heavy differentials reduce heavy oil producers' netbacks and at extreme levels could possibly result in some oil sands projects being uneconomic. Recently, the differential has narrowed because of increased market access with the delivery of western Canadian crude oil to Cushing, Oklahoma through the Spearhead Pipeline and into the U.S. Gulf Coast through the reversed Mobil Pipeline.

FIGURE 7

Canadian Crude Oil Prices and Differential



2.1.2 Capacity Utilization on Major Routes

Pricing data is available for a number of injection and delivery points on pipeline systems. Even where this data is not available, another measure of adequate capacity is obtained by comparing throughput with capacity. The Board monitors capacity utilization for most of the large pipelines it regulates.

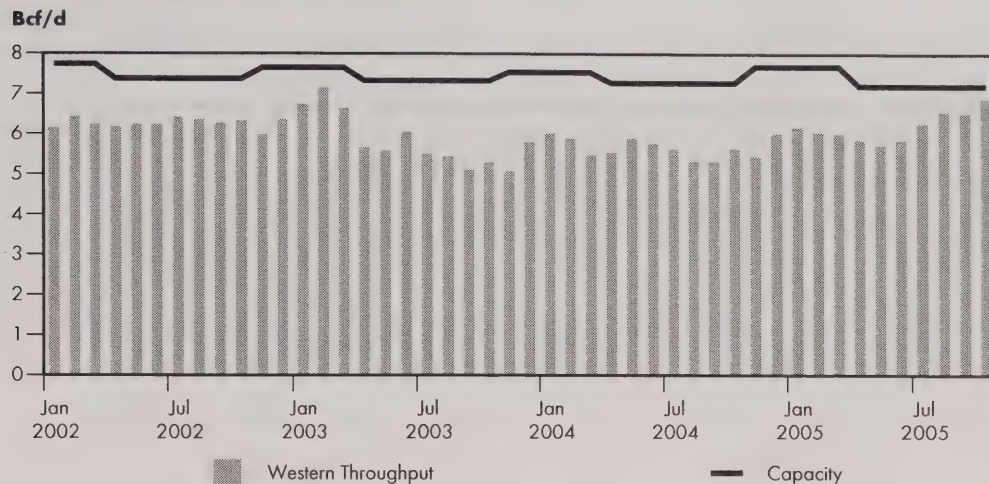
The following figures show pipeline average monthly throughput compared with capacity for some of the largest NEB-regulated pipeline systems, including the TransCanada Mainline, Foothills Pipe Lines Ltd. (Foothills), TransCanada B.C. System, Westcoast, Alliance Pipeline Ltd. (Alliance), Trans Québec & Maritimes Pipeline (TQM), Maritimes & Northeast Pipeline (M&NP), Enbridge Pipelines Inc. (Enbridge), Kinder Morgan Canada's Terasen Pipelines (Trans Mountain) Inc. (TPTM), Express and Trans-Northern Pipeline Inc. (TNPI).

Natural Gas

Figure 8 compares the average monthly throughput on the TransCanada Mainline (which is approximately equal to the amount of gas flowing east on the Mainline from Saskatchewan) to the capacity of TransCanada's prairie line. It demonstrates that while the prairie line has been operating at between 70 to 80 percent of capacity since April 2003, the volumes have increased in recent months. These higher volumes reflect increased eastern demand for Canadian gas due to last year's hot summer weather and reduced gas supplies (since September) from the Gulf of Mexico following the late summer hurricanes. Overall, the indicator shows that there has been adequate pipeline capacity to move volumes to eastern markets.

FIGURE 8

TransCanada Mainline Throughput vs. Capacity



The volumes shown in Figure 9 are the average monthly throughput on TransCanada's Foothills Pipeline (Sask.) compared with capacity. This pipeline connects with Northern Border Pipeline Ltd. (Northern Border) and Monchy, Saskatchewan to flow gas to the U.S. Midwest. While the Foothills (Sask.) capacity utilization has been running at an annual average of about 94 percent since 2002, there was some decline in the spring of 2005. The lower volumes were due to a period of unsold firm capacity on the connecting Northern Border pipeline, stemming from low seasonal demand and high storage levels.

FIGURE 9

Foothills Pipeline (Sask.) Throughput vs. Capacity at Monchy

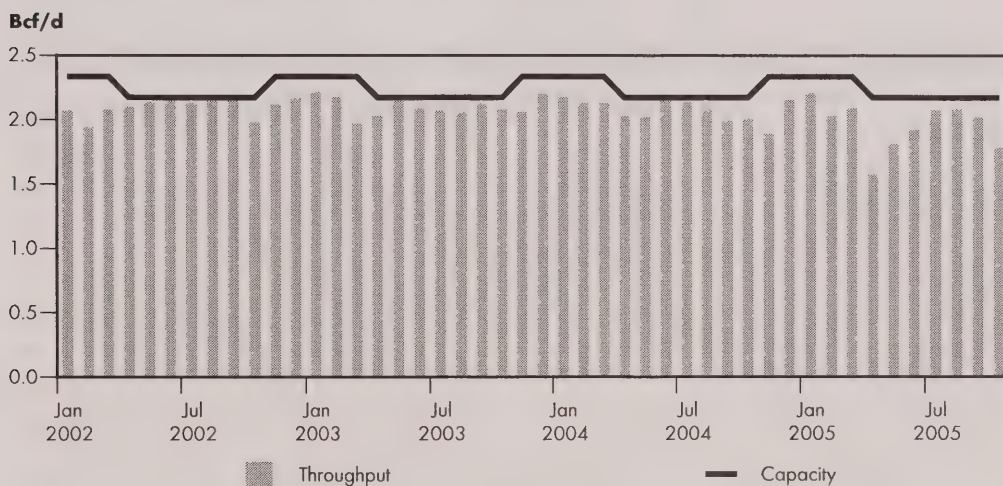


Figure 10 compares the average monthly throughput on Westcoast's Southern Mainline with the capacity on this system between Station 2 and the Sumas export point. This figure shows the seasonal nature of throughput on the Southern Mainline with higher volumes being transported during the peak winter months and less during the summer. One of the major contributors to low flows on Westcoast is the competition with production from the U.S. Rockies region which also has access to the U.S. Pacific Northwest market via Williams' Northwest Pipeline system. A warm winter and increased hydro power generation in British Columbia and the U.S. Pacific Northwest reduced gas flows on this pipeline in early 2006. In fact, the peak flow levels were lower than normal, as was the duration of the winter peak.

FIGURE 10

Westcoast Mainline Throughput vs. Capacity

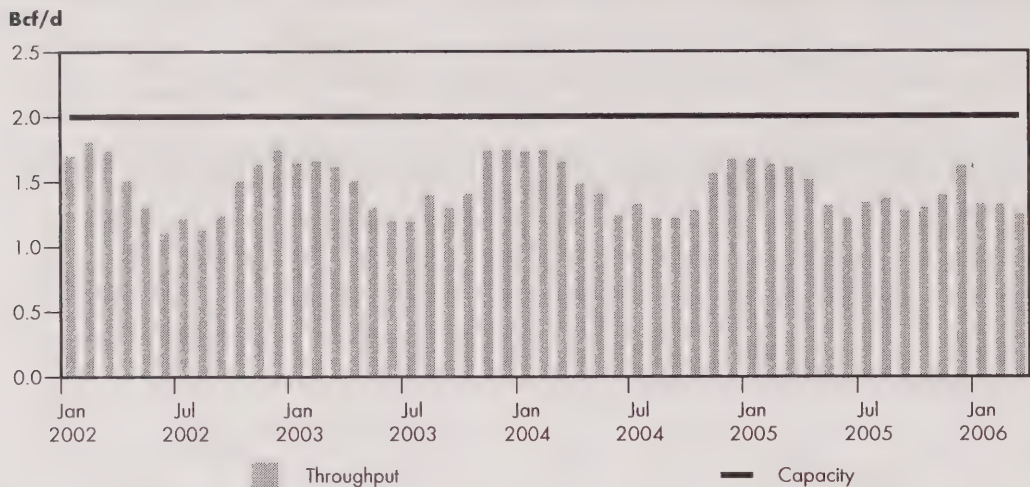


Figure 11 shows the average monthly throughput and capacity on the TransCanada B.C. System. The annual average capacity utilization dropped from about 77 percent in February 2002 to about 60 percent in March 2006, and there is spare capacity on this pipeline to export gas through Kingsgate. In California, which is the B.C. System's primary market region, market players have transportation options enabling them to access supply from the Rocky Mountains, San Juan and Permian basins, in addition to the Western Canada Sedimentary Basin (WCSB).

FIGURE 11

TransCanada B.C. System Throughput vs. Capacity at Kingsgate

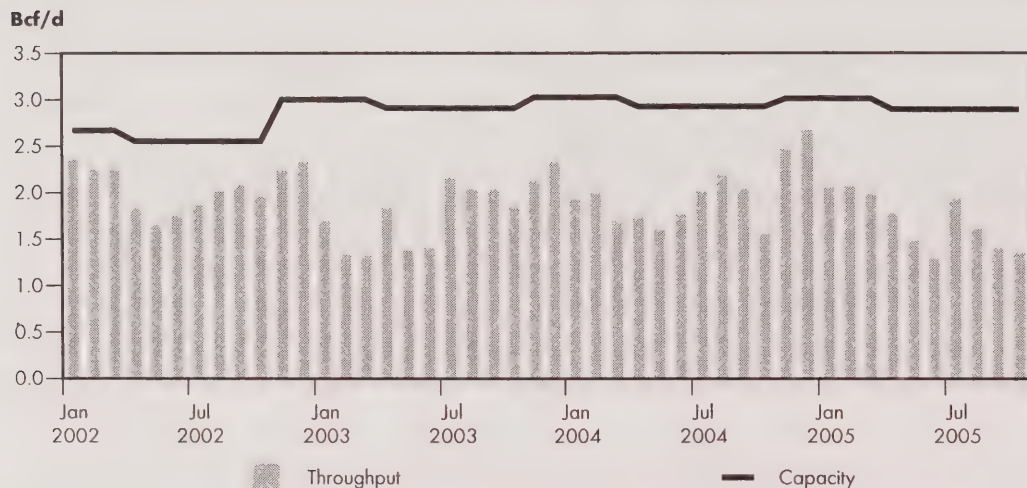


Figure 12 shows the average monthly throughput on the Alliance system relative to physically available capacity levels. Alliance offers approximately $37\,534\,10^3\text{m}^3/\text{d}$ (1.325 Bcf/d) of firm service capacity, and makes any additional capacity available to its contracted shippers pro rata as Authorized Overrun Service (AOS). Available AOS levels are determined on a daily basis and may be used at the cost of fuel only. The total available capacity is variable, depending on such factors as ambient temperature and compressor unit availability (as influenced by maintenance schedules). Alliance's total available capacity has essentially been fully utilized since the commencement of service, with all available firm service contracted on a long-term basis.

FIGURE 13

Alliance Throughput vs. Capacity

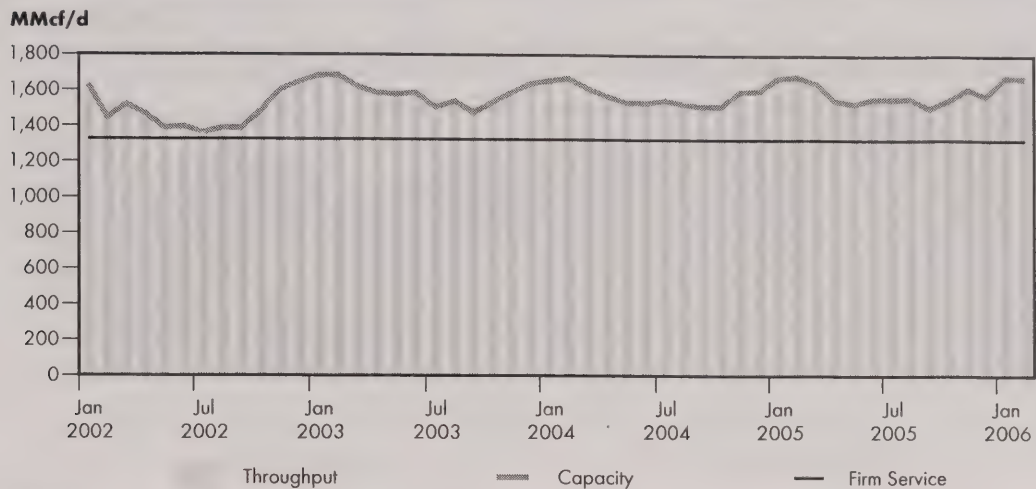


Figure 13 compares the average monthly throughput and capacity on TQM. This figure shows the seasonal nature of the throughput on this pipeline, with more volumes being transported during the peak winter months. With the annual average capacity utilization of around 60 percent, there is spare capacity on this pipeline which delivers gas between the TransCanada Mainline, connecting TQM at Saint-Lazare on the Ontario and Québec border, and TQM's endpoints at Saint-Nicolas (south shore of Québec City) and East Hereford (New Hampshire state border). However, with the limited compression on the system needed to meet TQM's delivery pressure at the East Hereford export point, the available spare capacity is very sensitive to the actual load distribution along the pipeline. Higher system utilization in 2005 reflects increased exports at East Hereford due to reduced gas supplies from the Gulf of Mexico following the late summer hurricanes.

FIGURE 14

Trans Québec & Maritimes Throughput vs. Capacity

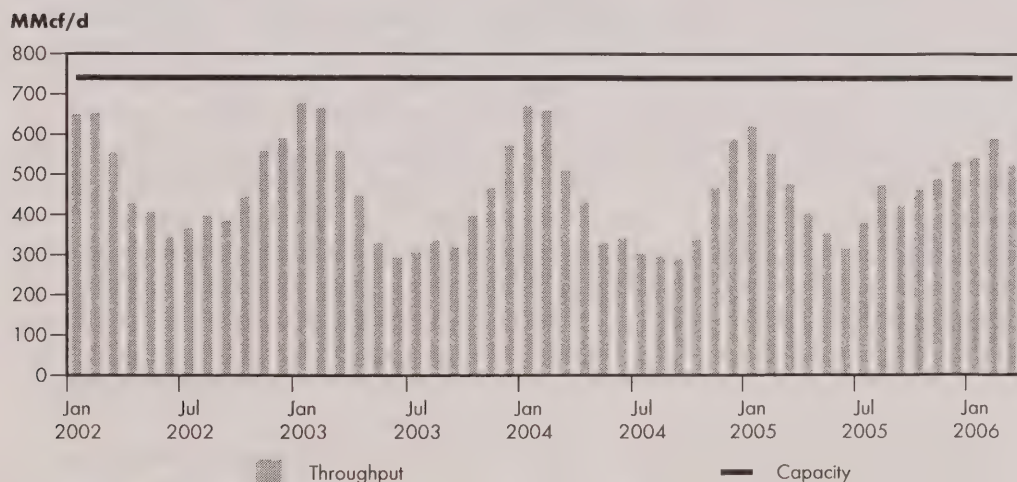
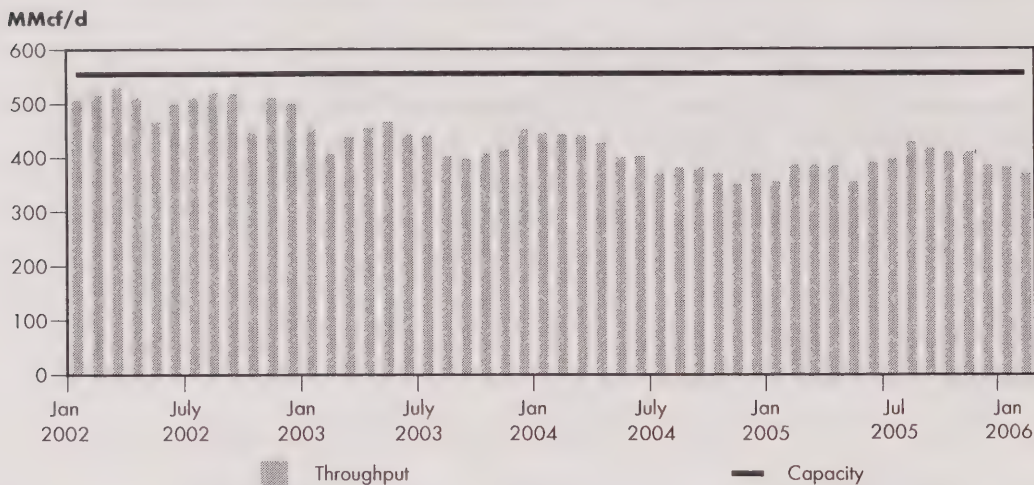


Figure 14 compares the average monthly throughput on the M&NP pipeline with its capacity. The annual average capacity utilization has been declining from about 92 percent in 2002 to an average of about 70 percent in 2005. The drop in this pipeline's utilization stems from declining natural gas production from Nova Scotia's Sable Offshore Energy Project. The variations in throughput are primarily related to changes in gas supply.

Maritimes & Northeast Pipeline Throughput vs. Capacity



Although the Dawn-Parkway corridor is not regulated by the NEB, it is a key link between the Dawn hub and growing markets in eastern Canada and the U.S. Northwest. Last year the Ontario Energy Board (OEB) approved Union Gas' Phase 1 Expansion, expected to be in service by November 2006. This year, Union filed an application with the OEB for its Phase 2 Expansion. If approved, the expansion is expected to be in service by 1 November 2007. Market demand for capacity in this corridor is expected to remain robust due to the liquidity of Dawn as a transactional trading point given its market reach.

Oil

Determining the capacity and throughputs on an oil pipeline can be complex as there are a number of factors to be considered: the type of product, product mix, type of batching, pipeline configurations and bottlenecks.

The Enbridge system originates in Edmonton, Alberta and extends east across the Canadian prairies to the U.S. border near Gretna, Manitoba to join the Lakehead system in the U.S. It is the largest crude oil pipeline in the world and the primary transporter of crude oil from western Canada to markets in eastern Canada and the U.S. Midwest. The system consists of several lines transporting crude oil, NGLs and refined petroleum products. Figure 15 illustrates Enbridge Mainline throughput versus capacity for all lines. In 2005, Enbridge transported roughly 224 600 m³/d (1.4 million barrels per day) of crude oil, petroleum products and NGLs. In the first quarter of 2006, Enbridge operated at around 80 percent of capacity (Figure 15). Certain lines, particularly Lines 3 and 4, which transport heavy oil, have been operating at or close to full capacity, with some apportionment (see Section 2.1.3).

In November 2005, Kinder Morgan purchased Terasen Inc., owner of the Trans Mountain pipeline system. This purchase made Kinder Morgan a major oil pipeline player in Canada. TPTM's current capacity, assuming some shipments of heavy oil, is 35 700 m³/d (225 Mb/d). The pipeline has been operating at or near capacity for several years and on many occasions has been under apportionment (see Section 2.1.3). However, the capacity indicated in Figure 16 is 45 300 m³/d (285 Mb/d). This higher capacity assumes no heavy crude oil shipments. On average, particularly in the last two years, 20 percent of TPTM's crude oil receipts at Edmonton are heavy and because of the increased viscosity, pipeline capacity was reduced to 35 700 m³/d (225 Mb/d).

FIGURE 15

Enbridge Pipeline Throughput vs. Capacity

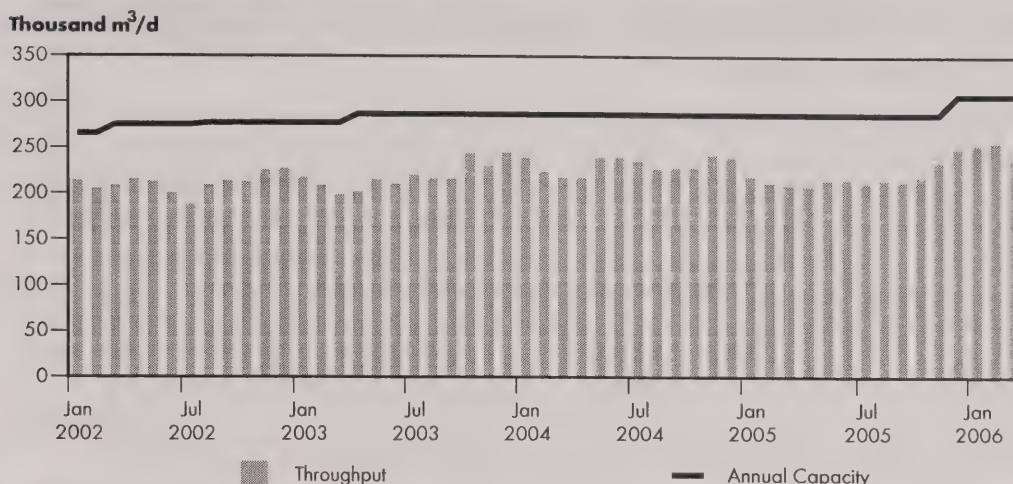
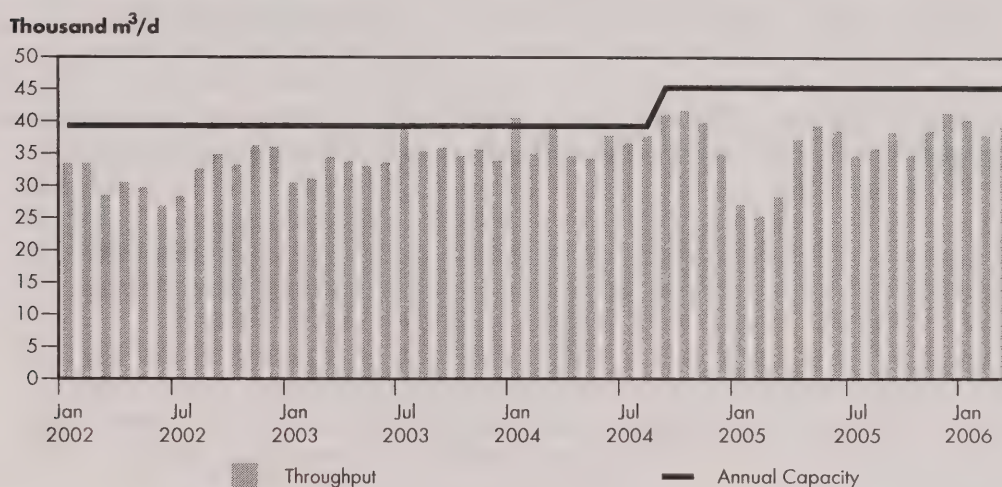


FIGURE 16

TPTM Throughput vs. Capacity²



On 5 July 2005, Terasen applied to the NEB for a capacity increase of 5 600 m³/d (35 Mb/d). It was approved on 10 November 2005 and the in-service date is April 2007.

In the first quarter of 2006, TPTM operated at approximately 86 percent of capacity (see Figure 16). Though the system did not operate at capacity, TPTM was under apportionment in January, February and March of 2006. Many factors contributed to this apportionment, including growing oil sands supply coupled with increased demand from Washington State refiners and crude oil shipments off the Westridge Dock.

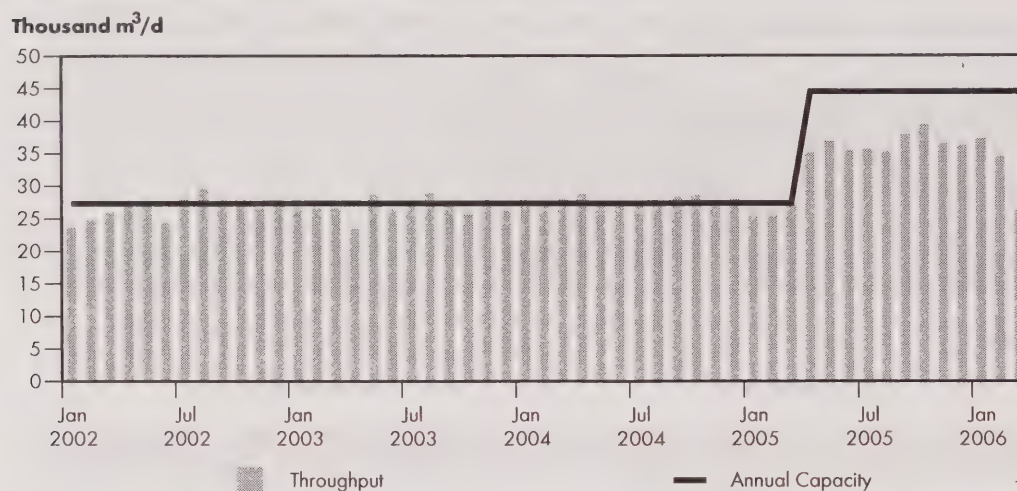
During the past several years, Express has been operating at capacity. In April 2005, Express completed its 17 600 m³/d (100 Mb/d) expansion, bringing the total capacity to 44 900 m³/d (280 Mb/d). Express is the only crude oil pipeline in western Canada that operates under long-term take-or-pay agreements with its shippers for the majority of its capacity.

² Capacity shown is light crude oil only (0% heavy).

In the first quarter of 2006, Express operated at approximately 73 percent of capacity (Figure 17). Throughputs were reduced in March 2006 due to apportionment on the Platte Pipeline system in the U.S.

FIGURE 17

Express Throughput vs. Capacity



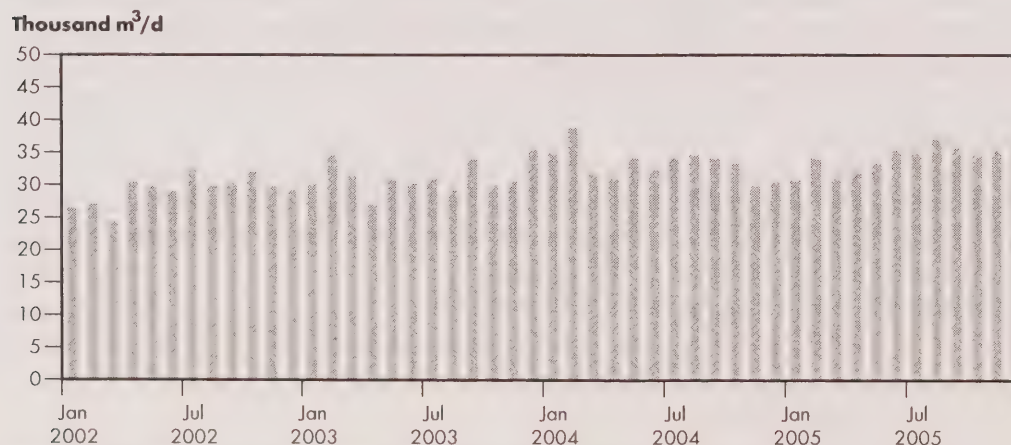
TNPI is a refined petroleum products pipeline. Historically, the pipeline system extended from Nanticoke, Ontario to Montreal, Quebec serving petroleum industry terminals along the route. In 2003, TNPI applied to the Board to increase the line capacity between Montreal and Farran's Point, Ontario from 10 500 m³/d (66 150 Mb/d) to 21 000 m³/d (132 300 Mb/d) and to reverse the direction of flow between Farran's Point and Metropolitan Toronto from a west-to-east direction to an east-to-west direction.

The Board approved TNPI's application to reverse the line and to accept take-or-pay obligations from Petro-Canada and Ultramar for 91 percent of the capacity. The remaining 900 m³/d or nine percent of the capacity from Farran's Point to Toronto is available for spot shipments.

The expansion and the reversal, which took place in November 2004, were a response to declining shipments on the TNPI system and the closure of Petro-Canada's refinery in Oakville, Ontario. Increased deliveries from Montreal on TNPI serve markets in Ontario formerly served by Petro-Canada's Oakville refinery and by Ultramar by rail from Quebec (Figure 18).

FIGURE 18

Trans-Northern Pipelines Inc. Throughputs



Calculating TNPI's capacity is difficult due to multiple delivery locations and the different capacities on each line segment.

2.1.3 Apportionment

Oil pipelines normally operate as common carriers, although pipelines such as Express, Enbridge Line 9 and TNPI operate with long-term shipper take-or-pay agreements. Common carriers require shippers to nominate their volumes for delivery into a pipeline on a monthly basis without a contract for the pipeline's capacity. When shippers nominate more oil or oil products in a given month than the pipeline can transport, shippers' volumes are apportioned (reduced) based on the tariff set out by the pipelines. Apportionment can be caused by factors such as growing supply, increased demand, pipeline reconfigurations and refinery maintenance. Some recent apportionment data for Enbridge, TPTM and Cochin is shown below.

Enbridge

Historically, Lines 2 and 4 were dedicated to the transportation of heavy crude oil and Line 3 was dedicated to the transportation of light and medium crude oils. In the third quarter of 2005, Enbridge completed the Terrace Phase III expansion project to facilitate the growth in heavy crude oil. By converting Line 2 from heavy to light service and Line 3 from light to heavy service, it increased its heavy capacity by 39 000 m³/d (245 700 b/d and reduced its light capacity by 18 400 m³/d (115 920 b/d).

As illustrated in Table 1, Line 4 was under apportionment once between August 2005 and February 2006. In February, each shipper was required to reduce its volume, resulting in a three percent reduction. There are a number of factors that caused the apportionment: increased throughput from the oil sands, apportionment on the Platte system in the U.S., increases in conventional production in North Dakota for injection at Cromer, Manitoba and Clearbrook, Minnesota; pipeline reconfiguration; and refinery maintenance.

Enbridge's Line 9 has a capacity of 38 150 m³/d (240 000 b/d) and transports oil from Montreal, Quebec to Sarnia, Ontario. In contrast to last year, there was no apportionment on the line between August 2005 and February 2006. This was partly due to increased volumes of western Canadian light conventional crude oil being processed in Ontario refineries.

TABLE 1

Enbridge Apportionment³

	Aug-05	Sept-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06
Line 4 Apportionment	0%	0%	0%	0%	0%	0%	3%
Throughput (10 ³ m ³ /d)	104.3	103.4	102.4	113.0	90.4	113.9	111.0

Terasen Pipelines (TransMountain) Inc.

Apportionment on TPTM is calculated separately for domestic destinations, export destinations and Westridge Dock destinations (as shown in Table 2 as Domestic, Export and Dock). Apportionment in November 2005 through to March 2006 reflects increased volumes associated with expansion in the oil sands and the higher market demand for Canadian crude. In addition, heavy crude oil volumes also increased during this time limiting capacity on the TPTM system. With improving market economics TPTM is delivering increasing volumes of western Canadian crude oil into Washington

State refineries as well as for export over the Westridge Dock which contributed to apportionment at both of these locations.

Following three notices of motion and an oral argument heard on 11 April 2006, the Board released its Decision approving the inclusion of a premium in the Tariff as a means of allocating capacity to the Westridge Dock. Further information can be found in the Board's letter decision dated 12 April 2006 and MH-2-2005.

TABLE 1

TPTM Apportionment

	Aug-05	Sept-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06
Apportionment								
Domestic	0%	0%	0%	12%	0%	16%	32%	34%
Export	0%	0%	0%	18%	15%	18%	33%	43%
Dock	0%	0%	0%	74%	0%	30%	87%	93%
Throughput ($10^3\text{m}^3/\text{d}$)	35.9	38.4	34.9	38.7	41.4	40.3	38.0	39.2

Cochin

The Cochin pipeline is the largest and longest NGL pipeline in Canada. It transports propane, ethane, ethylene and butane, although no butane has been transported since 2002. Ongoing maintenance work on the pipeline has affected the available capacity. The lower throughput volumes and apportionment in September 2005 was caused by unexpected downtime required for immediate repairs. Because ethylene was already in the pipeline, there was no flexibility to transport larger volumes of other products (ethylene has a higher vapour pressure than propane and ethane and reduces the capacity of the pipeline).

Effective 7 March 2006, Cochin suspended the transportation of ethylene until at least the fall of 2007 due to a defect found in the U.S. portion of the pipeline and went on a voluntary pressure restriction. The pressure is not to exceed 900 psi and applies to the whole line from Fort Saskatchewan, Alberta to Windsor, Ontario. Without ethylene in the pipeline, propane and ethane shippers are not expected to face apportionment. The average capacity will be around 10.3 to 11.9 $10^3\text{m}^3/\text{d}$ (64 890 b/d to 79 970 b/d). Once the pressure restrictions are lifted, capacity is expected to return to 17.5 $10^3\text{m}^3/\text{d}$ (110 250 b/d).

TABLE 2

Cochin Apportionment

	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06
Apportionment	0%	18%	0%	0%	0%	0%	0%	0%
Throughput ($10^3\text{m}^3/\text{d}$)	8.6	5.6	9.9	6.0	9.7	9.2	9.8	7.7

2.1.4 Summary of the Adequacy of Pipeline Capacity

Overall, the examination of throughput and capacity on NEB-regulated natural gas pipelines shows that pipeline capacity is adequate across the country although there may be limitations at some points depending upon markets, storage and seasonal shifts. The demand for natural gas varies seasonally and, as a result, the flow of natural gas through some Canadian pipelines can be variable as well.

⁵ Line 4 was the only line on the Enbridge system out of western Canada that was apportioned during this period.

Where possible, the use of storage helps to reduce the variation in flows and allows pipeline capacity to be used more efficiently with higher annual capacity utilization.

Oil pipeline capacity, however, is tight and is expected to remain tight through 2008, even with the current expansions underway (Figure 28). This is being driven by increases in crude oil supply from the oil sands and in conventional production in North Dakota and PADD IV. In the first quarter of 2006, the price of heavy crude oil was, on average, 42 percent less than the price of light crude oil. This compares to a more typical light/heavy differential of around 30 percent. The light/heavy differential is typically wider during the winter months, reflecting reduced demand for asphalt and lower gasoline demand. However, the size of the differential in the first quarter reflects pressures building from an increase in supply, in this case from the oil sands, pipeline constraints and lack of refinery capacity to process heavier crude oil. Recently, the differential has narrowed as a result of market extension into Cushing, Oklahoma and the U.S. Gulf Coast through the Spearhead Pipeline and the Mobil Pipeline, respectively.

2.2 Pipeline Tolls

2.2.1 Pipeline Tolls Index

Another indicator of a hydrocarbon transportation system's efficiency is whether pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). One of the factors the Board uses to analyze this is year-to-year variations in a benchmark toll for each of the major pipelines it regulates (e.g., TransCanada's Eastern Zone toll or Westcoast's T-South Export toll). Under cost-of-service regulation, pipeline tolls can vary from year-to-year for various reasons. For example, a significant expenditure to modify or expand a system to meet shippers' needs could increase or decrease toll levels depending on the specific circumstances. Falling throughput or contract demand leading to lower capacity utilization could lead to a significant toll increase. The following sections review variations and trends of some NEB-regulated pipeline tolls since 1997.

Natural Gas Pipeline Tolls

The benchmark tolls⁴ for TransCanada's Mainline, Westcoast, Foothills, the TransCanada B.C. System (B.C. System), TQM, M&NP, Alliance, and the GDP deflator⁵ normalized to the year 2001 are shown in Figure 19.

The increase in TransCanada's benchmark toll between 1997 and 2004 is mainly attributed to a large amount of decontracting on the Mainline during that period, particularly after the startup of the Alliance pipeline in 2000. This toll tracked the GDP deflator fairly closely from 2001 to 2004. However, in 2005 the toll fell, primarily due to increased contract demand and is below the level that it was in 2000.

Westcoast's tolls have increased moderately except for two years, 2000 and 2005. In 2000, Westcoast's benchmark toll increased more than 10 percent from the previous year primarily due to a large amount of non-routine pipeline integrity costs and in 2005, this toll increased by over 15 percent due to decontracting of firm services.

⁴ The benchmark tolls are: TransCanada Eastern Zone; Westcoast T-South Export; Foothills Zone 9; B.C. System Postage Stamp; TQM Saint Lazare to Trois-Rivières; M&NP Postage Stamp; and Alliance monthly demand toll.

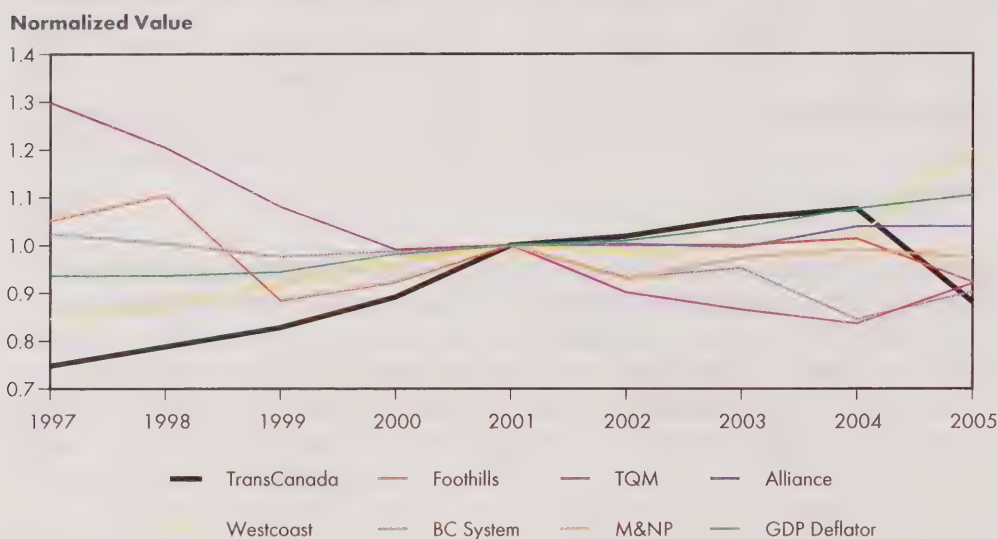
⁵ The GDP deflator for 2005 is an estimate using actual data for the first half of the year and data estimated by Infometrica for the second half of the year.

The B.C. System, Foothills and TQM's benchmark tolls were lower in 2005 than in 1997. The B.C. System's benchmark toll decreased in 2004 primarily because of an increase in throughput volumes (over 10 percent) from 2003. Foothills benchmark toll dropped in 1999 as a result of a cost-effective expansion of its system. TQM's benchmark toll has decreased since 1997, although it increased somewhat in 2005. The decline was due, in part, to the Portland Natural Gas Transmission System (PNGTS) extension in 1999, which increased throughput over 30 percent from 1998.

M&NP and Alliance's benchmark tolls have been relatively constant since beginning operations at the end of 1999 and 2000 respectively.

FIGURE 19

NEB-Regulated Gas Pipeline Benchmark Tolls



Oil Pipeline Tolls

The benchmark tolls for Enbridge, TPTM, TNPI, Express and the GDP deflator, normalized to the year 2001⁶, are shown in Figure 20.

Enbridge's benchmark toll has risen fairly steadily over the period, growing at a faster pace than the GDP deflator, except for a drop in 2002. The tolls increased the most in 2000 and 2004. The increase in 2000 was due to unforeseen lower throughput levels in the previous year. Under its negotiated settlement, Enbridge was able, in the following year, to recapture the revenue shortfall due to the lower throughput. The 2004 increase was primarily due to operating at lower capacity utilization as a result of throughput not filling a recent capacity expansion. Higher fixed costs were spread across relatively lower volumes resulting in higher tolls.

TPTM's benchmark toll rose steadily from 1997 to 2003 but fell in the last two years. There was a large increase in 1999 due to low forecast throughput. During TPTM's first incentive toll settlement, tolls were calculated on forecast volumes. In 1999 the throughput forecast was 17.9 percent lower than the 1998 forecast, which led to a corresponding increase in the benchmark toll. In 2004, the benchmark toll dropped primarily due to the disposition of 2003 deferrals for higher revenue. TNPI and Express's benchmark tolls moved in line with the GDP deflator from 1997 to 2005.

⁶ The benchmark tolls are: Enbridge Edmonton to International Border near Chippewa; TPTM Edmonton to Burnaby; TNPI Oakville to Montreal; and Express 15-year.

FIGURE 20

NEB-Regulated Oil Pipeline Benchmark Tolls

Normalized Value

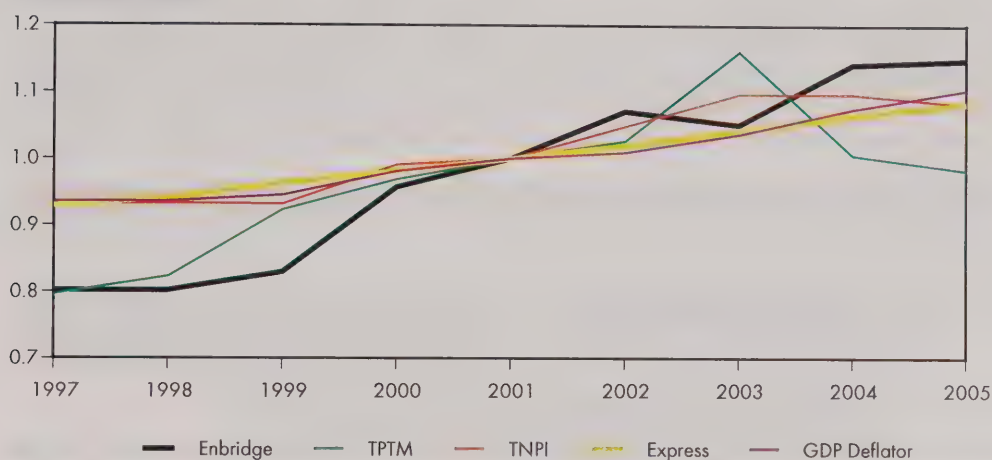
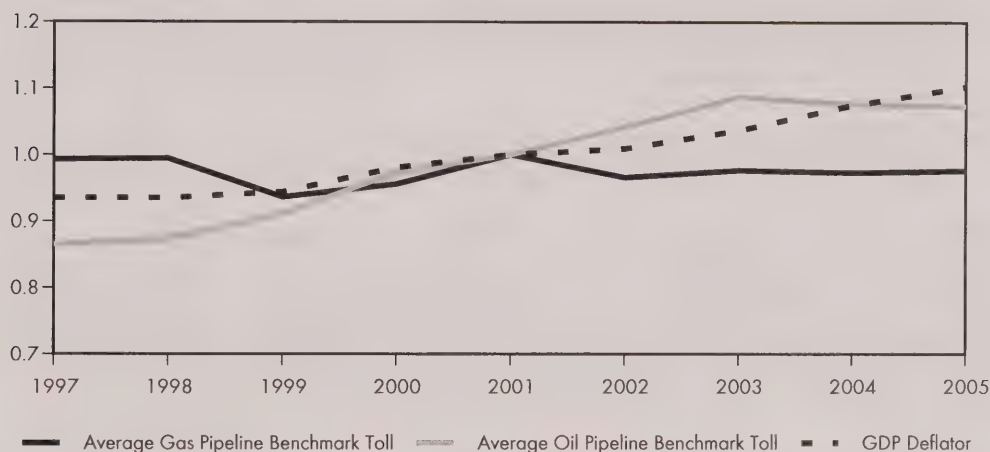


FIGURE 21

Oil and Gas Pipeline Benchmark Tolls

Normalized Value



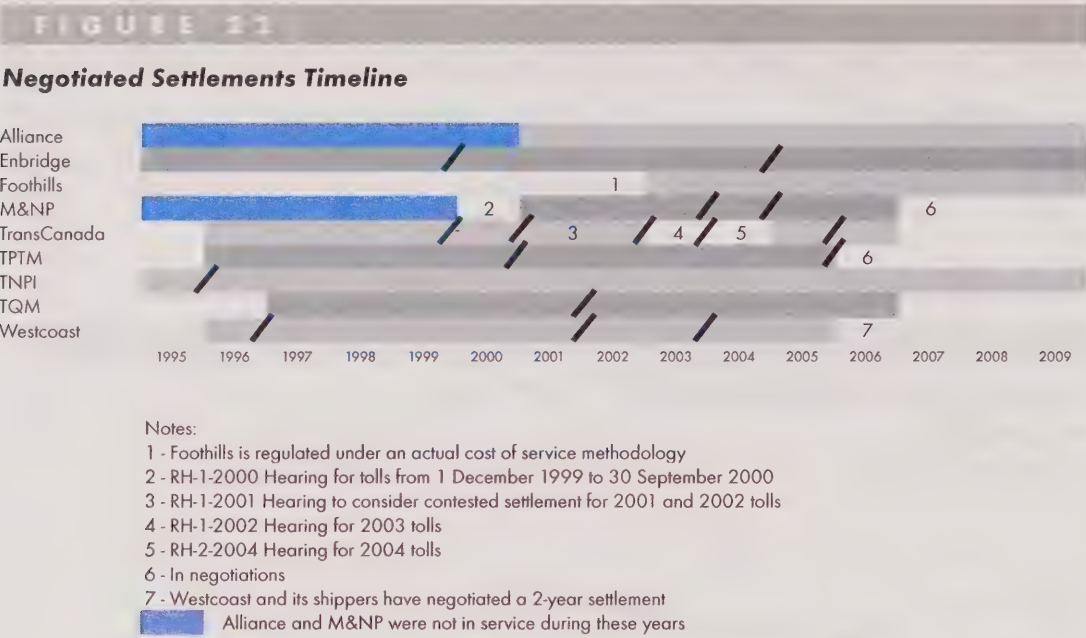
Comparison of Gas and Oil Pipeline Tolls

The average gas and oil benchmark pipeline tolls (reported in Figures 19 and 20) and the GDP deflator are graphed in Figure 21. From 1997 to 2005, oil pipeline tolls increased on average more than gas pipeline tolls, whereas gas pipeline tolls experienced more variation than oil pipeline tolls.

2.2.2 Negotiated Settlements

To improve the effectiveness of the regulatory process, the Board has supported the use of negotiated settlements as an alternative to toll hearings since the mid-1980s. In September 1988, the Board issued its first *Guidelines for Negotiated Settlements*. These guidelines were subsequently updated in August 1994 and revised again in June 2002 to provide flexibility when addressing contested settlements.

Most of the major Group 1 companies have successfully negotiated multi-year settlements with their shippers. Beginning in 1995, the Board approved a succession of multi-year settlements. These agreements generally included incentives to reduce costs and provisions to share savings between the pipeline company and its shippers. Several of these multi-year settlements have been renegotiated upon their expiry. For example, Enbridge Pipelines has negotiated three consecutive five-year settlements covering the period 1995 to 2009. Similarly, TPTM and TQM have had two successive five-year settlements and are in the process of renegotiating new ones. Refer to Figure 22 which shows, for each pipeline company, the years that were covered by negotiated settlements.



Negotiated settlements have contributed to a significant reduction in the regulatory burden for all parties with less time spent participating in hearings and a corresponding reduction in costs associated with the hearing process. This may be somewhat offset by the increased time spent by pipeline companies and their shippers in task force meetings. Parties note that the greater use of task forces and settlements has increased the collaboration between pipeline companies and shippers and resulted in a better alignment of interests.

Some settlements have included various innovative performance mechanisms such as incentives for cost control and performance improvement standards. Examples of the latter include the service standards in Westcoast’s 1997–2001 settlement and the service and reliability metrics in Enbridge’s 2005–2009 incentive agreement.

Negotiated settlements have also increased the length of period for which tolls are set. Rather than annual toll proceedings, a number of agreements have terms of five years or longer, which provides greater predictability and stability.

2.3 Shipper Satisfaction

2.3.1 NEB Pipeline Services Survey

The Board conducted its second Pipeline Services Survey in early 2006 to obtain direct feedback from the shippers on the level of service provided by major NEB-regulated pipeline companies. The Board also uses this survey to obtain feedback from shippers on the Board's regulatory performance with respect to tolls and tariffs.

This year, the Board used a web-based survey tool to send the survey directly to shippers via e-mail. Shippers were sent one survey for each pipeline the shipper utilized during the past year. Each survey asked the shippers to provide their company's corporate views on the services provided by the pipeline being surveyed and on the services provided by the Board. The overall response rate of 33.5 percent was a significant improvement over last year's rate of 23 percent.

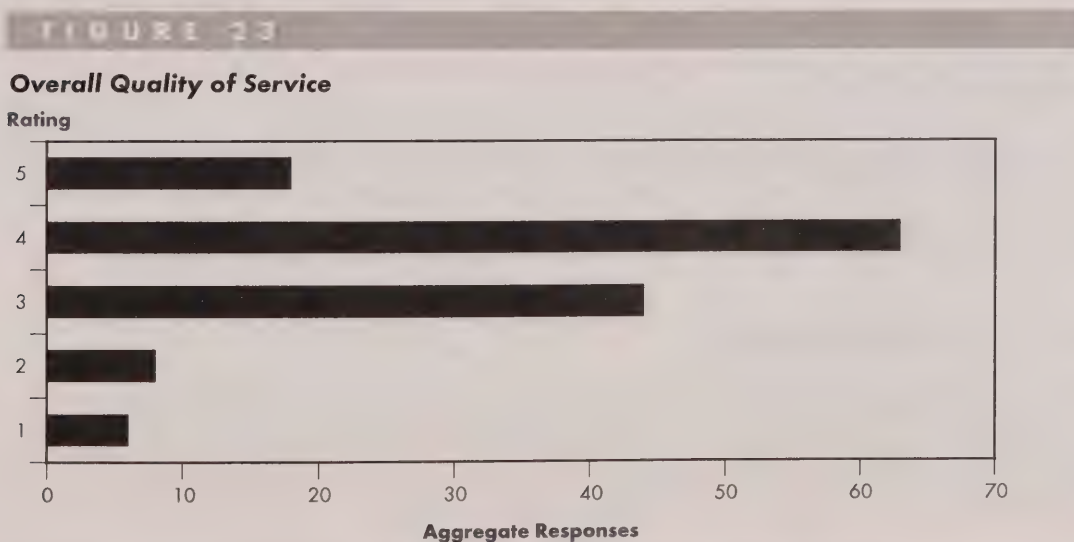
After analyzing the survey responses, the Board published a summary of the aggregate results on its website. They included the industry average and distribution of responses for each question and a summary of major themes. In addition, the Board provided each pipeline company and its shippers with detailed company-specific results. These results include the pipeline company's average rating, distribution of responses for each question as well as the verbatim comments received from shippers, excluding the names of the respondents.

The Board follows up on the survey results, including feedback on the Board, by meeting with pipeline companies and shippers.

Appendix 2 provides the aggregate scores on all survey questions. For the complete report on the aggregate results, refer to www.neb-one.gc.ca/Publications/SurveyResults.

Pipeline Services

Figure 23 shows the aggregate results for the survey question that asked shippers to rate their satisfaction with the overall quality of service provided by their pipeline companies over the last year (1 indicates "very dissatisfied" and 5 indicates "very satisfied"). While the average score of 3.57 was lower than the score of 3.78 in last year's survey, shippers still appear reasonably satisfied with the services provided.



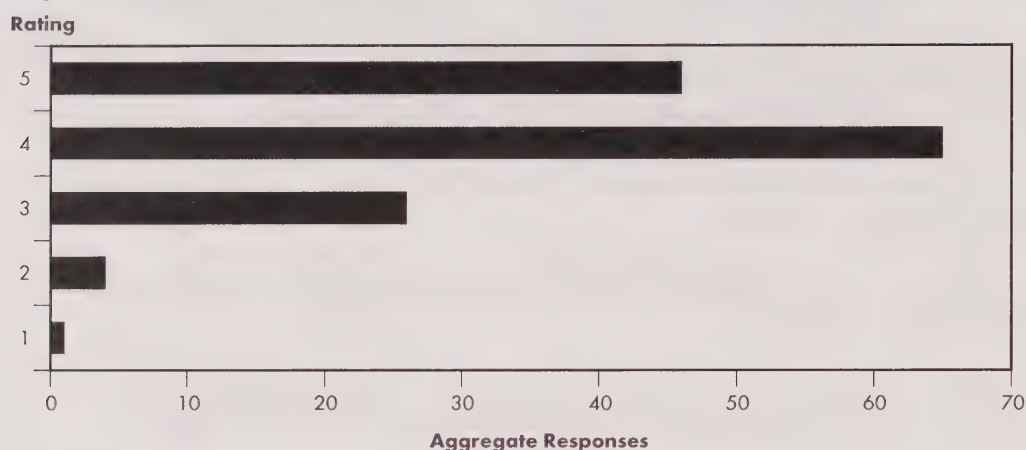
The three areas where the pipeline companies rated the highest were the same areas as in last year's survey, as demonstrated by the scores on the following questions:

1. How satisfied are you with the physical reliability of the pipeline company's operations?
2. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?
3. How satisfied are you with the timeliness and usefulness of operations information (outages, available capacity, scheduled maintenance, flows, etc.) provided by the company?

The high level of satisfaction with the physical reliability of pipeline operations indicates that energy products are reliably being delivered to markets (see Figure 24).

FIGURE 24

Physical Reliability of Operations



The three areas where shippers believe that pipeline companies could improve the most are very similar to the areas in last year's survey. The questions where the pipeline companies rated lower were:

1. How satisfied are you that this pipeline company's tolls are competitive?
2. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?
3. How satisfied are you with the collaborative process (negotiations or task force meetings) utilized by this pipeline company?

Performance of the Board

The survey also indicated that approximately two-thirds of shippers are either satisfied or very satisfied with the Board's performance in creating an appropriate regulatory framework and with the Board's processes to resolve disputes. While this was a slight improvement over the previous year's survey, shippers did identify areas where the Board could improve its processes and performance.

2.3.2 Formal Complaints

If shippers are unable to resolve concerns with the pipeline, they can bring a complaint to the NEB. It can then be dealt with through appropriate dispute resolution (ADR), through a formal complaint process or the parties may continue to negotiate towards resolution. There were two shipper complaints this past year requiring a formal process before the Board:

Abitibi Consolidated Company (Abitibi) and Boise White Paper, L.L.C. (Boise)

Centra Transmission Holdings Inc., a Group 2 company, applied to the Board to increase its tolls. Subsequently two shippers, Abitibi and Boise wrote to the Board requesting additional time to examine Centra's application. The Board subsequently initiated a written process to deal with the matter. The Board approved Centra's application for increased tolls, subject to certain amendments. Additional information can be found in the Board's Reasons for Decision RHW-3-2005.

Petro-Canada Oil and Gas (PCOG)

PCOG applied to the Board requesting the issuance of an order requiring Westcoast to grant the permanent firm service relocation of PCOG's Transportation North Long Haul firm service without the requirement to extend its existing service agreement by two years. On 4 May 2006, the Board issued its decision on PCOG's application. The Board found that the practice of requiring a term extension does not constitute unjust discrimination and that permanent relocation may be considered a service. The Board was also of the view that not enough information concerning the appropriate level of consideration was included in the submissions. The Board directed Westcoast to bring the matter of permanent firm service relocation and the appropriate level of consideration back to the Board after discussion with the Tolls and Tariff Task Force. Further, the Board advised that PCOG's term extension, if any, will reflect the final Board decision in this matter. Additional information can be found in the Board's file, 4775-W005-1-17.

2.3.3 Service Enhancements

Pipeline companies modify their services on an ongoing basis as circumstances change or innovative ideas are brought forward. Normally, the pipeline or its shippers bring these proposed service enhancements to their tolls task force for discussion and review prior to submission to the Board and ultimate adoption. This past year, for example, Westcoast applied to the Board to introduce firm service enhancements of term differentiated rates and authorized over run service in Zones 3 and 4 and cross corridor crediting in Zone 3. The Board approved Westcoast's application. More information can be found in the Board's Reasons for Decision RHW-1-2005.

If the task force is unable to resolve the issue, a party may bring the issue directly to the Board. This past year, one such enhancement was brought to the Board and subsequently approved.

Coral Energy Canada Inc. (Coral)

Coral applied to the Board to modify the Firm Transportation Risk Alleviation Mechanism (FT-RAM) pilot, a service enhancement proposed by TransCanada for its Mainline. The Board approved Coral's application and directed TransCanada to modify its Mainline Transportation Tariff to reflect this decision. Additional information can be found in the Board's Reasons for Decision RHW-2-2005.

2.3.4 Summary of Shipper Satisfaction

This past year, it was found that shippers are reasonably satisfied with the services provided by the pipeline companies and the Board's performance in creating an appropriate regulatory framework and the Board's processes to resolve disputes. For both the pipeline companies and the Board, shippers identified areas for improvement in service. Areas of improvement for the pipeline companies are outlined in the previous section. Shippers also noted that the Board could improve its processes through which tolls and tariffs are determined by streamlining those processes and actively engaging stakeholders so that it better understands

the market context in which it makes decisions. The Board is taking this feedback into consideration. For example, in its Strategic Plan for 2006 – 2009 the Board identified the objective for its regulatory processes to be efficient, seamless and responsive to all stakeholders.

2.4 Pipeline Financial Integrity and Ability to Attract Capital

In order for a hydrocarbon transportation system to be efficient, pipeline companies must have adequate financial integrity to attract capital on reasonable terms and conditions. This enables them to effectively maintain their systems and build new infrastructure to meet the market's evolving needs. The following sections review and discuss a number of the factors used to assess these areas.

2.4.1 Financial Ratios

Financial statement information can be used to create financial ratios that are used for assessing a company's performance and financial integrity. Evaluating a financial ratio is most meaningful when the ratio of a particular company is compared with a benchmark or industry standard over time. These ratios can be used to evaluate a company's liquidity, operating performance, growth potential, and risk. However, care must be exercised in the collection and interpretation of financial ratios. Some reported financial information may pertain to a parent company, which may include non-regulated assets and/or assets from different industries.

The following sections specifically outline and discuss some of the ratios used to assess the financial risk and operating profitability of certain NEB-regulated pipeline companies. The final section outlines and discusses some NEB-approved financial ratios.

Financial Risk

Financial risk is the risk inherent in a company's use of debt and other obligations that have fixed payments. It differs from business risk which is the risk attributed to the nature of a particular business activity and, for pipelines, typically includes supply, market, regulatory, competitive and operating risks. Financial risk increases as the proportion of debt increases in relation to shareholders equity. An increase in debt may obligate a company to make more and larger fixed payments in the future. From a bondholder's perspective, a company with above average financial risk could have problems making interest payments. From an equity holder's perspective, a company's level of financial risk gives some indication of its financial viability.

Ratios used to evaluate a company's level of financial risk include interest coverage, fixed-charges coverage, and cash flow-to-total debt and equivalents.

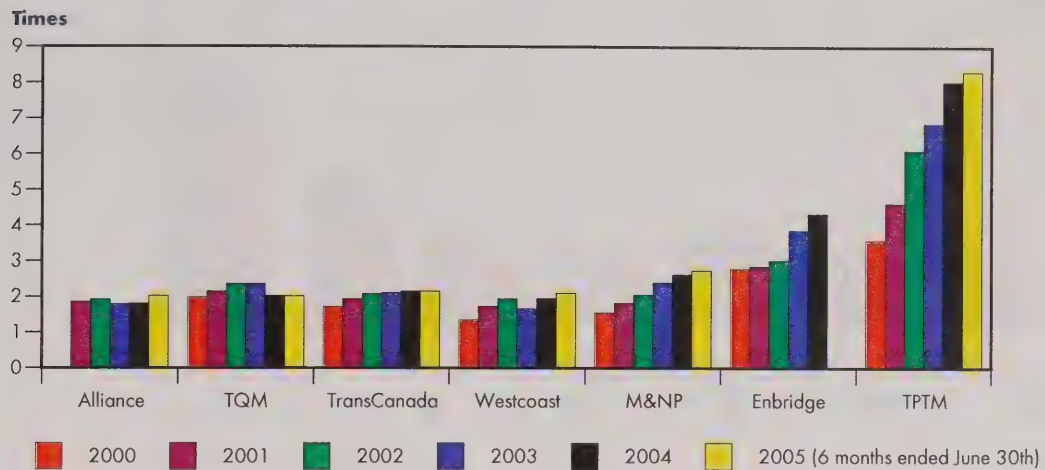
Interest and Fixed-Charges Coverage Ratios

An interest coverage ratio assesses a company's ability to make interest payments and repay its debt obligations. It is defined as Earnings Before Interest and Taxes (EBIT) divided by interest charges. A fixed-charges coverage ratio also assesses the ability to make interest payments and repay debt obligation; however, it also takes into consideration other types of fixed payments a company is obligated to make. It is defined as EBIT less other fixed-charges divided by interest and other fixed-charges. Higher ratios indicate an increased likelihood that the company will be able to meet its obligations and may indicate that it has unused borrowing capacity.

The fixed-charges coverage ratios for some NEB-regulated pipeline companies, as calculated by the Dominion Bond Rating Service (DBRS), are shown in Figure 25. The average fixed-charges coverage

FIGURE 25

Fixed-Charges Coverage Ratios



Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge in 2005.

ratio for these companies for the six months ending June 2005 is 3.22 times. TPTM's fixed-charges coverage ratio is higher, primarily due to a deemed common equity ratio of 45 percent (larger than its peers), which means it carries less debt and, therefore, has lower fixed payments.

From 2000 to 30 June 2005, the fixed-charges coverage ratio for these pipeline companies increased on average by 49 percent⁷. This growth was primarily driven by M&NP, Enbridge and TPTM. No company saw its fixed-charges coverage ratio decline from its 2000 level. The consistent increases in fixed-charges coverage ratios is one metric signaling a decrease in these pipeline companies' financial risk, when considered as a group.

Cash Flow-to-Total Debt and Equivalents Ratio

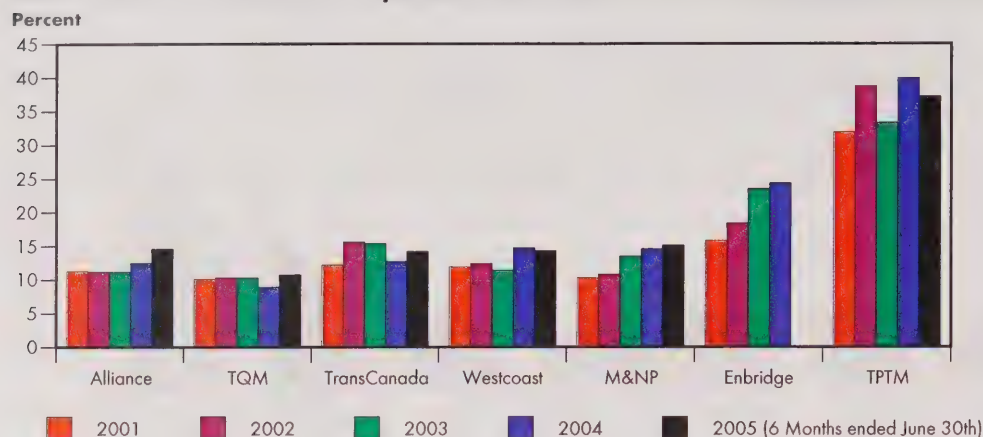
The cash flow-to-total debt and equivalents ratio is another way of assessing a company's ability to meet its debt obligations and fixed payments. It is defined as operating cash flow divided by total debt and equivalents. Again, higher ratios indicate an increased likelihood of a company being able to meet its obligations and indicate that it has greater borrowing capacity.

The cash flow-to-total debt and equivalents ratios for some NEB-regulated pipeline companies, as calculated by DBRS, are shown in Figure 26. The average cash flow-to-total debt and equivalents ratio for these companies was 17.68 percent for the 6 months ending June 2005. TPTM's cash flow-to-total debt and equivalents ratio was higher than its peers for the same reason that its fixed-charges coverage ratio was higher.

On average, the cash flow-to-debt and equivalents ratio for these pipeline companies has grown by 20 percent from 2000 to 2005. The increase has been steady without any noteworthy periods of deterioration. Similar to the fixed-charges coverage ratio, the consistent increase in cash flow-to-total debt and equivalents ratios is another metric which signals that, on average, these pipeline companies' financial risk has been decreasing.

⁷ Historically, Enbridge's fixed-charges and cash flow-to-debt and equivalents ratios were much higher than the average of the other pipeline companies in Figures 20 and 21. Since these ratios were not provided for Enbridge in 2005, the pipeline company average for 2005 and the percentage increase since 2000 and 2001 respectively, may be biased downward.

FIGURE 3.6

Cash Flow-to-Total Debt and Equivalents Ratios

Source: DBRS

N.B. There was no cash flow-to-total debt and equivalents ratio reported for Enbridge in 2005.

Operating Profitability**Return on Common Equity**

ROE is commonly used to assess the operating profitability of a company. ROE is defined as net income divided by common equity. For NEB-regulated pipeline companies, this is the return on the equity portion of the rate base that is approved by the Board. A higher ROE is typically preferred by both bondholders and, even more so, by equity investors.

Table 4 shows the achieved ROE for several NEB-regulated pipeline companies from 2000 to 2005 along with the NEB-approved ROE in accordance with the RH-2-94 Formula⁸ (RH-2-94 Formula ROE). Alliance, Enbridge, M&NP and TPTM are not subject to the RH-2-94 Formula ROE as they have all negotiated an ROE with their shippers⁹. As per their respective negotiated settlements, Enbridge and TPTM are not required to submit their achieved ROE to the NEB. Therefore, neither of these pipeline companies are included in Table 4. Westcoast's Field Services Division is also not subject to the ROE formula as it is under light-handed regulation¹⁰. Its tolls for gathering and processing services are negotiated individually with shippers.

From 2000 to 2005, most pipeline companies subject to the RH-2-94 Formula ROE have consistently had ROEs in the mid-to-high nine percent range (except for Westcoast Transmission which has achieved higher ROEs). The RH-2-94 Formula ROE for 2006 is 8.88 percent.

NEB-Approved Ratios

When the Board approves a Group 1 pipeline company's tolls for a specified time period, it typically also approves a ROE and deems a common equity ratio for the regulated entity. Therefore, the Board has influence over the operating profitability and financial risk of some Group 1 pipeline companies.

⁸ Formula used to determine the ROE for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, and later amended to eliminate rounding.

⁹ These pipelines settlements are subsequently approved by the Board.

¹⁰ Light-handed regulation is essentially regulation on a complaint basis with rules. Additional information can be found in RHW-1-98.

TABLE 4

Achieved ROEs and the RH-2-94 Formula ROE (Percent)

	2000	2001	2002	2003	2004	2005
Alliance	11.21	11.25	11.25	11.25	-	-
Foothills	9.90	9.61	9.53	9.79	9.56	9.46
M&NP	13.80	14.20	12.95	12.31	13.75	14.31
TQM	9.96	10.21	9.80	10.21	9.84	9.92
TransCanada	9.99	9.72	9.95	10.18	9.83	9.66
B.C. System	9.90	6.86	9.53	8.21	8.51	9.46
Westcoast Field Services	-	13.62	14.87	6.76	11.63	12.48
Westcoast Transmission	12.68	15.84	13.44	12.93	10.28	10.82
NEB RH-2-94 Formula	9.90	9.61	9.53	9.79	9.56	9.46

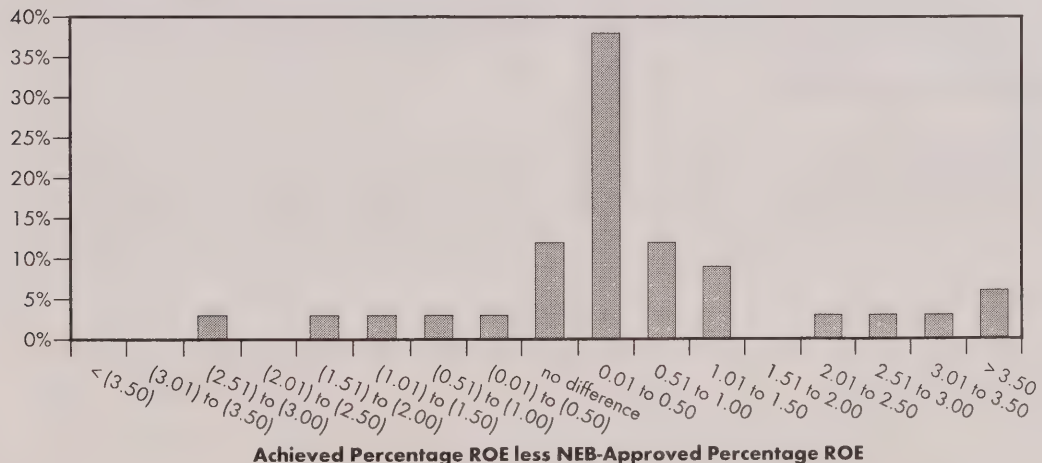
Source: NEB Surveillance and Annual Reports; dash indicates not available

NEB-Approved Return on Common Equity

NEB-approved ROEs have great influence over the ROEs that are actually achieved. Achieved ROEs can vary from NEB-approved levels for various reasons, such as incentive and profit sharing mechanisms and cost reductions over the year.

Figure 27 charts the difference between achieved ROEs and NEB-approved ROEs for TransCanada, B.C. System, TQM, Westcoast Transmission system, and M&NP¹¹. Enbridge and TPTM are not required to submit their achieved ROEs to the Board as per their negotiated settlements. Westcoast Field Services is not included as it is subject to light-handed regulation. Foothills and Alliance are not included in Figure 27 as neither is able to over- or under-perform on ROE in accordance with their respective cost-of-service methodologies.

FIGURE 27

Achieved and NEB-Approved ROE for the Years 1999 to 2005**Frequency**

11 TransCanada, B.C. System, TQM and Westcoast Transmission system have NEB-approved ROEs subject to the RH-2-94 Formula ROE, whereas M&NP has a NEB-approved ROE of 13 percent.

From 1999 to 2005, pipeline companies (included in Figure 27) have met or exceeded their NEB-approved ROEs 85 percent of the time. This stability and predictability of their operating profitability is positive for both bondholders and equity investors. It also highlights that these pipeline companies, in many cases, have been able to meet and outperform approved levels through cost reductions, incentive and profit sharing mechanisms.

NEB-Approved Deemed Common Equity Ratios

A common equity ratio is defined as the percentage of common equity in a company's capital structure. This ratio is often used to evaluate a company's financial risk. Higher common equity ratios increase the likelihood of a company being able to meet its obligations. The Board approves a deemed common equity ratio¹² for most of the Group 1 pipeline companies that it regulates.

Table 5 shows the deemed common equity ratio for some NEB Group 1 pipeline companies. TransCanada, Westcoast Transmission, B.C. System and Foothills have had their deemed common equity ratios increased between 2000 and 2006. These increases are credit positive and lower the financial risk of the pipeline companies.

TABLE 5

Deemed Common Equity Ratios (Percent)

	2000	2006
Alliance	30	30
Foothills	30	36
M&NP	25	25
TQM	30	30 *
TransCanada	30	36
B.C. System	30	36
Westcoast Transmission	30	31 *

* TQM and Westcoast Transmission's 2006 deemed common equity ratios are interim.

2.4.2 Credit Ratings

In Canada, pipeline credit ratings are determined by three independent credit rating agencies: DBRS, Standard & Poor's (S&P), and Moody's Canada Inc. (Moody's). A comparison of the rating scales for DBRS, S&P and Moody's can be found in Appendix 1. Credit ratings, like stock prices, generally reflect the consolidated operations of the entire company and not solely the regulated portion. Thus, using these ratings as an accurate measure of the creditworthiness of a NEB-regulated pipeline owned by a company with both regulated and non-regulated operations, such as TransCanada and Enbridge, must be interpreted with some care. In addition, credit ratings are somewhat subjective in that a company's ratings are the expert opinion of the credit rating agency, which may result in different ratings by different agencies.

Dominion Bond Rating Service

In assigning a credit rating to a particular company, DBRS attempts to consider all meaningful factors that could impact the risk of maintaining timely payments of interest and principal in the future. While key considerations will vary from industry to industry, some of the common factors considered for most ratings are: core profitability, asset quality, strategy and management strength, and financial and business risk.

The following factors are also important considerations in deriving the credit ratings for pipelines and electric and gas utilities: regulatory factors, competitive environment, supply and demand considerations, and regulated versus non-regulated activities. DBRS credit ratings for several NEB-regulated pipeline companies are shown in Table 6. As indicated, these ratings have remained stable from 2000 to the present, varying from BBB (high) to A (high).

¹² A deemed common equity ratio is a notional capital structure used for rate-making purposes that may differ from a company's actual capital structure.

Standard & Poor's

A credit rating from S&P reflects its current opinion of a company's overall capacity to pay its financial obligations. S&P bases its ratings on the overall creditworthiness of a consolidated company. Therefore, the rating of a wholly-owned subsidiary, in the absence of meaningful ring-fencing measures, generally reflects the creditworthiness of the parent. S&P's opinion may also apply to specific financial obligations.

In S&P's rating methodology, a company rated "A" has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than companies in higher-rated categories. A company rated "BBB" has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to weaken the company's capacity to meet its financial commitments.

S&P credit ratings for several NEB-regulated pipeline companies are shown in Table 7. This table indicates that these ratings have been relatively stable from 2000 to the present, ranging from BBB (stable) to A (negative).

Both DBRS and S&P have, at various times, expressed an opinion that the ROE awarded through the RH-2-94 Formula and the deemed equity ratios awarded by the Board are low by international standards. Notwithstanding these comments, the ratings assigned by both of these agencies for the NEB-regulated companies are all investment grade.

Moody's

Moody's credit analysis focuses on the fundamental factors and key business drivers relevant to an issuer's long-term and short-term risk profile. The foundation of Moody's methodology rests on two basic questions:

1. What is the risk to the debt holder of not receiving timely payment of principal and interest on this specific debt security?
2. How does the level of risk compare with that of all other debt securities?

Like S&P, Moody's credit rating is its current opinion of a company's overall capacity to pay its financial obligations and focuses its ratings on the overall creditworthiness of a consolidated entity. In so doing, Moody's measures the ability of an issuer to generate cash in the future. This determination is built on an analysis of the strengths and weaknesses of the individual issuer compared with those of its peers worldwide. Moody's also takes into consideration factors external to the issuer, including industry or nation-wide trends that could impact the entity's ability to meet its debt obligations. Of particular concern is the ability of company management to sustain cash generation in the face of adverse changes in the business environment.

The rating histories for several NEB-regulated pipeline companies are provided in Table 8. All of Moody's ratings place these pipelines in the investment grade category, ranging from "medium grade" to "upper-medium grade".

DBRS Credit Rating History

Pipeline	2000	2001	2002	2003	2004	2005	Current
Alliance	BBB(high)	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
M&NP	A	A	A	A	A	A	A
TQM	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
TransCanada	A	A	A	A	A	A	A
Westcoast ¹	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
Enbridge	A(high)	A(high)	A(high)	A(high)	A(high)	A(high)	A(high)
Express ²	NR	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
TPTM	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)	discontinued / debt repaid
TNPI	NR	NR	NR	NR	NR	A(low)	A(low)

Notes: (1) Unsecured debentures; (2) Senior secured

NR Not reported

S&P Credit Rating History

Pipeline	2000	2001	2002	2003	2004	2005	Current
TQM	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable
TransCanada	A-/Stable	A-/Stable	A-/Watch Negative	A-/Watch Negative	A-/Watch Negative	A-/Negative	A-/Negative
Westcoast	A-/Negative	A-/Stable	A-/Negative	BBB/Stable	BBB/Positive	BBB/Watch Negative	BBB/Stable
Enbridge	A-/Stable	A-/Negative	A-/Negative	A-/Stable	A-/Stable	A-/Stable	A-/Stable
TPTM	BBB+/Stable	BBB+/Stable	BBB+/Watch Negative	BBB/Stable	BBB/Stable	BBB+/Stable	discontinued / debt repaid

Moody's Credit Rating History

Pipeline	2000	2001	2002	2003	2004	2005	Current
Alliance ¹	Baa1	A3	A3	A3	A3	A3	A3
M&NP ²	A1	A1	A1	A1	A1	A2	A2
TransCanada ¹	A2	A2	A2	A2	A2	A2	A2
Enbridge	NR	NR	NR	NR	NR	NR	NR
Express ²	A3	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1

Notes: (1) Senior unsecured; (2) Senior secured

2.4.3 Comments by Investment Community

As noted previously, pipeline companies must be able to access capital markets to maintain and, potentially, expand their systems as the needs of the transportation market change. Board staff met with credit rating analysts, equity analysts (sell-side analysts), and suppliers of capital such as insurance and pension funds (buy-side analysts) to discuss their views on the ability of NEB-regulated pipeline companies to access capital markets, as well as their views on transportation markets and the current regulatory environment in Canada. This section reflects the views expressed in those meetings.

All parties expressed the view that there was no problem accessing debt markets at this time. In fact, utilities frequently enter the market to refinance their debt and, given the current liquidity in the markets, they have been able to do so at favourable spreads relative to government bonds.

Several analysts noted that Canadian regulation, including the ROE formula approach, provides transparency, predictability and stability, which are seen as highly beneficial. However, a number of analysts felt that the ROE generated by the NEB ROE formula and the formulas of other Canadian regulators were “a little too low” and not supportive of dividend growth or credit metrics. Although most analysts felt that utilities have good access to equity markets, the current level of ROEs was seen by some as impeding this access. As there has been, in most cases, adequate pipeline capacity from the WCSB in recent years, the ability of pipeline companies to access equity markets has not been significantly tested.

Many equity analysts publish their assessments of various companies for investors. Most of the analysts currently rate major NEB-regulated pipeline companies in the “Hold” or “Buy” categories. A number of equity analysts commented that where they have “Buy” ratings on Canadian utility stocks, they tend to reflect the prospects of the companies’ non-regulated businesses. A number of analysts also noted that companies have reduced costs and taken other steps to support corporate profit and dividend growth for several years, and they questioned how long this can continue.

It was noted that pipeline stocks are part of the interest-sensitive segment of the equity market and as such, low interest rates have been positive for valuations and the price-to-earnings ratio. The price-to-earnings ratios of Canadian utilities have been higher than their U.S. and European counterparts. The reasons given for this difference included greater growth opportunities in Canada given oil sands, northern gas, power infrastructure development, a more stable regulatory environment, as well as strong foreign interest in Canadian stocks in general.

2.4.4 Summary of Pipeline Financial Integrity and Ability to Attract Capital

The financial information and observations by the investment community are summarized as follows:

- Fixed-charges and cash flow-to-total debt and equivalents coverage ratios have increased since 2000.
- Deemed common equity ratios have increased since 2000.
- Achieved ROEs have, in most cases, been greater than or equal to their NEB-approved levels between 1999 and 2005.
- Achieved ROEs have been stable and predictable.
- Credit ratings continue to be strong.
- The investment community is of the view that NEB-regulated companies should have no problems accessing the capital markets at this time.

These observations signal that, currently, NEB-regulated pipelines have adequate financial integrity to attract capital on reasonable terms and conditions.

2.5 Proposed Pipelines

Many proposals to expand pipeline capacity or build new pipeline systems have been announced, applied for or recently approved. These include gas pipelines to growing markets in Canada and the U.S. and pipelines to ship western Canadian crude oil to the West Coast for delivery to Washington State and offshore markets, the U.S. Midwest and southern PADD II and the U.S. Gulf Coast (PADD III). More specifically, these project proposals include:

- new pipelines connecting northern gas supplies to existing gas infrastructure;
- natural gas expansions in the east to facilitate market development in eastern Canada and the U.S. Northeast; and
- pipeline laterals connecting existing infrastructure to proposed LNG receiving terminals in Nova Scotia and New Brunswick; and
- oil pipeline expansions and new pipeline proposals to facilitate the expected growth in the next decade in oil sands production.

Natural Gas

In the coming decade, demand for natural gas in North America is expected to exceed the growth in North American domestic supplies. In Canada, there are two sectors of growth that bear noting: oil sands projects in Alberta and electricity generation in Ontario.

The Canadian oil sands projects are a large and growing market for natural gas. Today, these projects consume about 0.7 Bcf/d. Natural gas is used to generate power, generate steam for in situ oil production and upgrade bitumen into synthetic blends. Gas demand for oil sands is expected to more than double to perhaps 2 Bcf/d over the next decade depending on the number of oil sands projects that proceed and the technology used.

In addition, Ontario's policy to remove 7 500 MW of coal-fired electrical generation by 2009 may require significant supplies of natural gas for power generation. While refurbishment of existing nuclear generation and the addition of renewable power sources may meet part of the requirement, it is possible that new electrical generation will primarily be fired by natural gas.

Table 9 summarizes currently announced Canadian natural gas pipelines and expansion proposals.

TABLE 9

Announced Canadian Natural Gas Pipelines and Expansions

Pipeline	Location	Capacity Increase (Bcf/d)	Proponents' Estimated Completion Date	Market to be Served
TransCanada Pipelines Limited - 2006 Eastern Mainline Expansion	Ontario, Québec	.310 ¹³	Late 2006	Central Canada, Northeastern U.S.
TransCanada Pipelines Limited - 2007 Eastern Mainline Expansion	Ontario, Québec	.377 ¹⁴	2007	Central Canada, Northeastern U.S.
Mackenzie Gas Pipeline	Mackenzie Delta, Northwest Territories to Alberta	1.2	2011	North America
Maritimes & Northeast Pipeline - Brunswick Pipeline	New Brunswick	0.75	2008	Atlantic Canada, Northeastern U.S.
Maritimes & Northeast Pipeline - Bear Head Pipeline	Nova Scotia	.813	N/A	Atlantic Canada, Northeastern U.S.

N/A Not Available

¹³ TCPL Eastern Mainline Expansion: Montreal/North Bay Shortcut to Iroquois delivery point.

¹⁴ TCPL Eastern Mainline Expansion: Montreal/North Bay Shortcut to Les Cèdres (148 MMcf/d), Philipsburg Extension to Philipsburg (12 MMcf/d) and Kirkwall/Niagara Line to Chippawa (217 MMcf/d).

Liquefied Natural Gas

A key supply source for North America is expected to be the rapidly developing global LNG market. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. Furthermore, advances in liquefaction and transportation technologies have lowered the unit cost of LNG by 30 percent over the past decade, enabling the use of LNG as a cost competitive source of gas supply in North America. In anticipation of growing natural gas requirements, expansions of some existing U.S. terminals and numerous new receiving facilities have been proposed, including sites in Canada as shown in Table 10.

However, there is uncertainty around the number of LNG terminals that will be built in Canada as well as the potential effects that imported LNG will have on gas markets and the pattern of natural gas flow. As discussed above, pipeline laterals will be required to connect LNG receiving terminals to existing natural gas pipeline infrastructure in order to deliver the gas to market.

TABLE 10

Proposed Canadian LNG Terminals

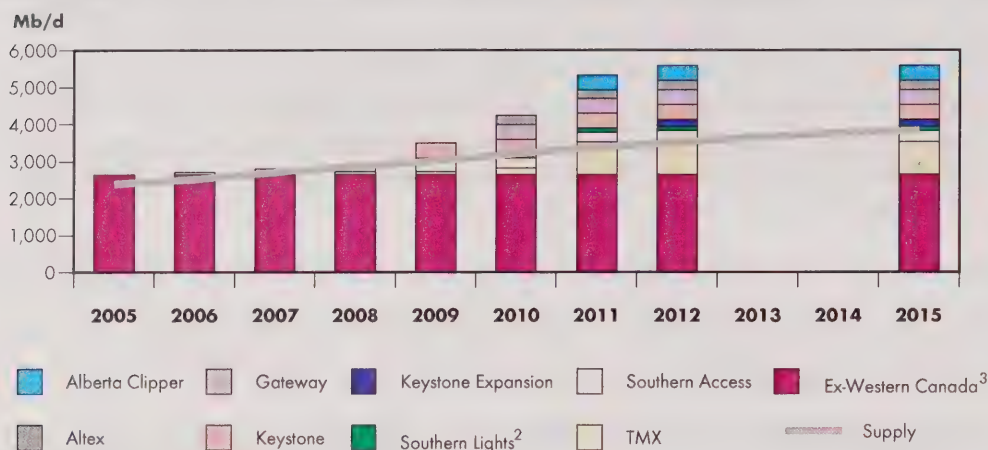


Terminal	Company	Location	Capacity (Bcf/d)	Proponents' Estimated Completion Date	Market to be Served
1 Bear Head	Anadarko Petroleum Company	Point Tupper, Nova Scotia	0.750 to 1.00	N/A	Atlantic Canada, Northeast U.S.
2 Keltic Goldboro	Keltic Petrochemicals Inc.	Goldboro, Nova Scotia	1.00	Late 2009	Atlantic Canada, Northeast U.S.
3 Cacouna Energy	TransCanada Pipelines Limited and Petro-Canada	Gros Cacouna, Québec	0.50	2010	Québec, Ontario, Northeast U.S.
4 Rabaska	Gaz Metro Limited Partnership, Gaz de France and Enbridge Inc.	Beaumont, Québec	0.50	2010	Québec, Ontario
5 Canaport	Irving Oil Limited and Repsol YPF	Saint John, New Brunswick	1.0	Late 2008	Atlantic Canada, Northeast U.S.
6 WestPac Prince Rupert	WestPac Terminals Inc.	Ridley Island, British Columbia	0.15 to 0.50	2009	Westcoast North America
7 Kitimat	Galveston Energy	Port of Kitimat, British Columbia	0.61	2009	Westcoast North America
8 Statia	Statia Terminals Canada Partnership	Canso Strait, Nova Scotia	0.50	N/A	Atlantic Canada, Northeast U.S.

N/A Not Available

FIGURE 23

NEB Supply Forecast and Proposed Pipeline Projects and Timing



1 The pipeline projects are listed alphabetically. In-service dates are proposed by the project sponsors

2 Edmonton to Cromer

3 Total pipeline capacity out of the WCSB

TABLE 11

Announced and Proposed Canadian Oil Pipelines and Expansions

Pipeline	Potential Filing Date	Capacity Increase (Mb/d)	Proponents' Estimated Completion Date	Market
Terasen (TPTM) Phase One TMX1 Phase Two TMX1	Filed July 2005 Filed February 2006	75 35 40	April 2007 Nov. 2008	PADD V Offshore/Far East
Southern Option TMPL TMX2 TMPL TMX3	01Q2007 N/A	700¹ 100 300	Jan. 2010 Jan. 2011	PADD V Offshore/Far East
Northern Option (TMX)	N/A	450	2011	PADD V Offshore/Far East
Enbridge Gateway (oil/diluent)	Fall 2006	400/150	Mid-2010	PADD V Offshore/Far East Alberta (diluent line)
Pembina Spirit (diluent)	N/A	100	April 2009	Alberta
Enbridge Southern Lights Southern Lights (diluent) Line 2 Expansion (oil) Edmonton to Cromer Cromer to Clearbrook Clearbrook to Superior	N/A	180 169 103 33 33	2009	Alberta PADD II PADD II PADD II
TCPL Keystone	June 2006	435	2009	Southern PADD II/ PADD III
Alberta Clipper	N/A	400	2010/11	Southern PADD II
Altex Energy	N/A	250	4Q2010	PADD III
Enbridge (Southern Access) Phase I Phase II Phase III	May 2006 N/A N/A	315 120 148 47	Oct. 2006 and Feb. 2007 2008/09 N/A	Midwest/Southern PADD II

N/A Not Available

¹ The 700 mb/d includes the existing capacity of 300 mb/d and the capacity additions from TMX2 and TMX3.

Oil

High crude oil prices and strong global demand are key drivers in the expansion of the oil sands. In this regard, many proposals to expand existing pipelines or build new facilities have been announced. Figure 28 shows that pipeline capacity out of western Canada could be tight in 2008.

Table 11 illustrates announced and potential expansions by Canadian pipelines. Additional details about these proposals are found in the EMA entitled *Canada's Oil Sands Opportunities and Challenges to 2015: An Update*, released in June 2006.

The proposals for pipeline expansion and construction of new pipelines indicate that the market is responding to increases in supply and demand.

2.6 Emerging Issues

While the transportation system is currently working well, there are a number of challenges facing the industry.

The demand for natural gas in North America is expected to increase by about two percent per year over the next decade. Conventional sources of supply for natural gas in North America are not likely to meet the increased demand. LNG is the fastest growing fuel source worldwide, and LNG's market share in North America is estimated to grow to about 15 percent within the decade. Although there is uncertainty around the number of LNG terminals that will be built in North America and the potential effects that imported LNG will have on the supply, demand and pattern of natural gas flow, LNG could become an important component of gas supply in Canada.

The construction of LNG terminals could have implications for existing pipeline transportation systems. For some pipelines, such as the TransCanada Mainline, this could result in volumes from the WCSB being displaced. For others, such as PNGTS and M&NP on the east coast, there is the possibility of higher capacity utilization on their systems. Direction of flow and toll design may also be affected. The PNGTS pipeline system has the potential for backhauls or reversal to import gas into Canada. There are also possibilities for expansion, reversals or backhauls in Quebec on TQM. Northern gas projects such as the Mackenzie Valley Pipeline or a pipeline from Alaska, if approved, and constructed, would also affect flows on existing systems.

If the expected increase in natural gas demand for power generation in Ontario materializes, it will impact the balance of supply and demand and consequent gas flows. The impact of this power generation on pipeline infrastructure will depend on the total amount of generation built and its location. New pipeline services may also be required to satisfy the needs of the power generation customers.

The expected growth in oil sands production is forcing industry to address questions such as which incremental markets to serve and how to expand the pipeline system to access them efficiently. Options include expanding existing systems and constructing new systems to access new markets in the U.S. and/or Asia. Given the large capital outlay and the relative irreversibility of the investment, market participants want to ensure that the optimal decisions are made.

There is concern in industry and in the financial community about the potential for insufficient pipeline capacity, particularly oil capacity, and conversely, the potential for excess capacity if too many projects go ahead. Other issues include the financial implications of increasing levels of competition among oil pipelines and the manner in which the regulatory process would unfold if numerous competing applications come before the NEB.

The challenge for the pipeline transportation industry is to have appropriate pipeline capacity in service to correspond to increases in production and growing market needs. For this to happen, there must be recognition of adequate lead times to achieve sufficient market support from amongst competing proposals, obtain regulatory approvals, arrange financing, mobilize labour and materials, and construct. A key component is that the regulatory process continues to be fair and effective with clear timelines and clear requirements.

Some of the above-noted issues will be settled among market participants; others may be examined in formal proceedings before the Board. The Board will continue to consult with stakeholders and seek input if and when any regulatory initiatives are pursued.

CONCLUSIONS

In the Introduction to this report, the Board identified its assessment criteria. Based on these criteria the Board continues to believe that, at the present time, the Canadian hydrocarbon transportation system is working effectively.

1. **There is adequate capacity in place on existing natural gas pipelines.** The basis differentials and capacity utilization charts show that most NEB-regulated gas pipelines have some excess capacity, even during the peak winter season. Some excess capacity out of the WCSB and the unprecedented high prices for energy has provided producers with the flexibility to access markets of their choice at most times. However, there are constraints at the market end of some pipelines as indicated by expansions currently underway.

Capacity is tight on oil pipeline transportation systems. While the capacity utilization charts show that there is spare capacity on some of the pipelines, additional capacity is required to meet the growing demand, provide flexibility and enhance market penetration. The need for additional capacity is best shown by the number of announced and proposed pipelines and expansions.

2. **Shippers continue to indicate that they are reasonably satisfied with the services provided by pipeline companies.** The results of the NEB Pipeline Services Survey again rate the physical reliability of pipeline operations very highly, while satisfaction with toll competitiveness was again identified as the area where shippers most had concerns.
3. **NEB-regulated pipeline companies are financially sound** and able to attract capital on reasonable terms and conditions. While it is recognized that some of the data and indicators reviewed is for the consolidated operations of pipeline companies, discussion with the investment community indicated that, at this time, NEB-regulated pipeline companies should have no difficulty raising capital. Extensive investment will be required in the future to provide needed infrastructure and the financing for those facilities will depend upon the characteristics of the projects and the financial markets at that time.

As identified in Section 2.5 there are a significant number of proposals to build or expand Canadian pipelines to deliver additional volumes of oil and natural gas to growing markets. Some of these proposals may be competing for the same sources of supply and perhaps the same markets.

The challenge from the NEB's perspective is to provide, in a timely manner, a fair and effective process that does not distort the market place investment decisions. This may involve coordinating with other jurisdictions. Investors desire clear regulatory processes with predictable timelines. New investment can be frustrated when timelines stretch out and unexpected regulatory hurdles materialize during the process. Further, unnecessary construction delays, for both expansions and new pipelines, can be costly to both energy consumers and producers as the development of new supplies is constrained.

The Board recognizes that this report is only a snapshot in time and does not include a comparison with or to pipeline transportation systems in other jurisdictions. As part of its mandate, the Board will continue to monitor the effectiveness of the transportation system and will continue to meet with parties to gain an understanding of all perspectives on this issue. The Board welcomes feedback on the measures and conclusions in this report and also welcomes suggestions for improvements to future reports.

The Board thanks those companies and organizations that directly or indirectly provided the information found in this report, including those that actively participated in the Pipeline Services Survey.

Debt Rating Comparison Chart

This chart provides a comparison of the rating scales used by DBRS, S&P and Moody's when rating long-term debt.

Credit Quality	DBRS	S&P	Moody's
Investment Grade			
Superior/High grade	AAA	AAA	Aaa
	AA (high)	AA+	Aa1
	AA	AA	Aa2
	AA (low)	AA-	Aa3
Good/Upper Medium	A (high)	A+	A1
	A	A	A2
	A (low)	A-	A3
Adequate/Medium	BBB (high)	BBB+	Baa1
	BBB	BBB	Baa2
	BBB (low)	BBB-	Baa3
Non-Investment Grade			
Speculative	BB (high)	BB+	Ba1
	BB	BB	Ba2
	BB (low)	BB-	Ba3
Highly speculative	B (high)	B+	B1
	B	B	B2
	B (low)	B-	B3
Very highly speculative	CCC	CCC	Caa1
	CC	CC	Caa2
	C	C	Caa3
	D	D	Ca
			C

Note: DBRS and S&P ratings in the CCC category and lower also have subcategories "high/+" and "low/-," and the absence of "high/+" and "low/-" designation indicates the rating is in the "middle" of the category.

S&P's also provides a Rating Outlook that assesses the potential direction of a long-term credit rating over the intermediate to longer term. A "Positive" outlook means that a rating may be raised; a "Negative" outlook means that a rating may be lowered and a "Stable" outlook means that a rating is not likely to change.

Pipeline Services Survey Aggregate Results

Below are the aggregate responses for each question in the survey. Respondents were asked to rate their satisfaction with the services they receive on a scale of 1 to 5, where 1 indicates “Very dissatisfied” and 5 indicates “Very satisfied”. See the Board’s website for the complete details.

1. How satisfied are you with the physical reliability of the pipeline company’s operations?

1	2	3	4	5	Average
1	4	26	65	46	4.06

2. How satisfied are you with the quality, flexibility and reliability of the pipeline company’s transactional systems (nominations, bulletin boards, reporting, contracting, etc.)?

1	2	3	4	5	Average
1	4	26	65	46	4.06

3. How satisfied are you with the timeliness and accuracy of the pipeline company’s invoices and statements?

1	2	3	4	5	Average
9	10	24	60	36	3.75

4. How satisfied are you with the timeliness and usefulness of operations information (outages, available capacity, scheduled maintenance, flows, etc.) provided by the pipeline company?

1	2	3	4	5	Average
4	12	37	73	16	3.60

5. How satisfied are you with the timeliness and usefulness of commercial information (tolls, service changes, new services, contract information, etc.) provided by the pipeline company?

1	2	3	4	5	Average
6	7	43	69	17	3.59

6. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?

1	2	3	4	5	Average
8	29	62	31	10	3.04

7. How satisfied are you with the accessibility and responsiveness of the pipeline company to shipper issues and requests?

1	2	3	4	5	Average
14	19	39	49	17	3.26

8. How satisfied are you that the pipeline company works towards fair and reasonable solutions when resolving issues?

1	2	3	4	5	Average
6	19	47	49	11	3.30

9. How satisfied are you with the suite of services offered by the pipeline company?

1	2	3	4	5	Average
4	17	51	55	10	3.37

10. How satisfied are you that this pipeline company's transportation tolls are competitive?

1	2	3	4	5	Average
14	29	45	38	11	3.02

11. How satisfied are you with the collaborative processes (negotiations or task force meetings) utilized by this pipeline company?

1	2	3	4	5	Average
8	12	51	42	8	3.25

12. How satisfied are you that the current negotiated settlement agreement or tariff arrangements work well to provide fair outcomes?

1	2	3	4	5	Average
7	11	48	47	6	3.29

13. How satisfied are you with the OVERALL quality of service provided by the pipeline company over the last calendar year?

1	2	3	4	5	Average
6	8	44	63	18	3.57

14. On an overall basis, has the pipeline company's quality of service in the last year:

Improved	19	13%
Remained the Same	110	78%
Decreased	13	9%
Total	142	100%

15. What are the things that this pipeline company does well?

16. What are the things that this pipeline company could do better?

17. How satisfied are you that the NEB has established an appropriate regulatory framework in which negotiated settlements for tolls and tariffs can be reached?

1	2	3	4	5	Average
7	7	30	72	8	3.54

18. When toll and tariff matters are not resolved through settlement, how satisfied are you with the Board's processes to resolve disputes?

1	2	3	4	5	Average
3	7	23	54	4	3.54

19. What could the Board be doing to improve its processes through which tolls and tariffs are determined?

Stakeholder Consultation

Alliance Pipeline Ltd.
 BMO Nesbitt Burns
 Canadian Association of Petroleum Producers
 Canadian Energy Pipeline Association
 CIBC World Markets
 Cochin Pipe Lines Ltd.
 CPP Investment Board
 Credit Suisse First Boston
 Dominion Bond Rating Service
 Enbridge Pipelines Inc.
 Express Pipeline Limited Partnership
 First Energy Capital
 Foothills Pipe Lines Ltd.
 Kinder Morgan Canada Inc.
 Maritimes and Northeast Pipeline
 Moody's Canada Inc.
 Ontario Teachers' Pension Plan
 RBC Capital Markets
 Standard & Poor's
 Sun Life Financial
 TD Newcrest
 Terasen Pipelines Inc.
 Trans Mountain Pipe Line
 Trans-Northern Pipeline Inc.
 Trans Québec & Maritimes Pipeline Inc.
 TransCanada PipeLines Limited
 Union Gas Limited
 Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission

Group 1 and Group 2 Pipeline Companies Regulated by the NEB

As of 31 December 2005

Group 1 Gas Pipelines

Alliance Pipeline Ltd.
 Foothills Pipe Lines Ltd.
 Gazoduc Trans Québec & Maritimes Inc.
 Maritimes & Northeast Pipeline Management Ltd.
 TransCanada PipeLines Limited
 TransCanada PipeLines Limited B.C. System
 Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission

Group 1 Oil and Products Pipelines

Cochin Pipe Lines Ltd.
 Enbridge Pipelines Inc.
 Enbridge Pipelines (NW) Inc.
 Terasen Pipelines (Trans Mountain) Inc.
 Trans-Northern Pipelines Inc.

Group 2 Natural Gas and Natural Gas Liquids Pipelines

AltaGas Pipeline Partnership
 AltaGas Suffield Pipeline Inc.
 AltaGas Transmission Ltd.
 Apache Canada Ltd.
 ARC Resources Ltd.
 Bear Paw Processing Company (Canada) Ltd.
 BP Canada Energy Company
 Canadian Hunter Exploration Ltd.
 Canadian Natural Resources Limited
 Canadian-Montana Pipe Line Corporation
 Centra Transmission Holdings Inc.
 Champion Pipeline Corporation Limited
 Chief Mountain Gas Co-op Ltd.
 DEFS Canada L.P.
 Devon Energy Canada Corporation
 Echoex Energy Inc.
 EnCana Border Pipelines Limited
 EnCana Ekwon Pipeline Inc.
 EnCana Oil & Gas Co. Ltd.
 EnCana Oil & Gas Partnership
 EnCana West Ltd.
 ExxonMobil Canada Properties
 Forty Mile Gas Co-op Ltd.

Huntingdon International Pipeline Corporation
Husky Oil Operations Ltd.
KEYERA Energy Ltd.
Many Islands Pipe Lines (Canada) Limited
Mid-Continent Pipelines Limited
Minell Pipeline Limited
Murphy Canada Exploration Company
Murphy Oil Company Ltd.
Nexen Inc.
Niagara Gas Transmission Limited
Northstar Energy Corporation
Omimex Canada, Ltd.
Paramount Transmission Ltd.
Peace River Transmission Company Limited
Pengrowth Corporation
Penn West Petroleum Ltd.
Petrovera Resources Ltd.
Pioneer Natural Resources Canada Inc.
Portal Municipal Gas Company Canada Inc.
Prairie Schooner Limited Partnership
Profico Energy Management Ltd.
Regent Resources Ltd.
Renaissance Energy Ltd.
St. Clair Pipelines Management Inc.
Samson Canada, Ltd.
Shiha Energy Transmission Ltd.
Sierra Production Company
Suncor Energy Inc.
Taurus Exploration Canada Ltd.
Union Gas Limited
Vector Pipeline Limited Partnership
County of Vermilion River No. 24 Gas Utility
2193914 Canada Limited
806026 Alberta Ltd.
1057533 Alberta Ltd.

Group 2 Oil and Products Pipelines

Amoco Canada Petroleum Company Ltd.
Aurora Pipe Line Company
Berens Energy Ltd.
BP Canada Energy Company
Dome Kerrobert Pipeline Ltd.
Dome NGL Pipeline Ltd.
Duke Energy Empress L.P.
Enbridge Pipelines (Westspur) Inc.
Ethane Shippers Joint Venture
Express Pipeline Limited Partnership
Genesis Pipeline Canada Ltd.
Glencoe Resources Ltd.
Husky Oil Limited
Imperial Oil Resources Limited

ISH Energy Ltd.
Montreal Pipe Line Limited
Murphy Oil Company Ltd.
NOVA Chemicals (Canada) Ltd.
PanCanadian Kerrobert Pipeline Ltd.
Paramount Transmission Ltd.
Penn West Petroleum Ltd.
Plains Marketing Canada, L.P.
PMC (Nova Scotia) Company
Pouce Coupé Pipe Line Ltd., as agent and general partner of the Pembina North Limited Partnership
PrimeWest Energy Inc.
Provident Energy Pipeline Inc.
Renaissance Energy Ltd.
SCL Pipeline Inc.
Shell Canada Products
Shell Canada Products Limited
Sun-Canadian Pipe Line Company
Taurus Exploration Canada Ltd.
Yukon Pipelines Limited
1057533 Alberta Ltd.



GOAL 3

**Canadians benefit from efficient
energy infrastructure and markets.**

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CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT



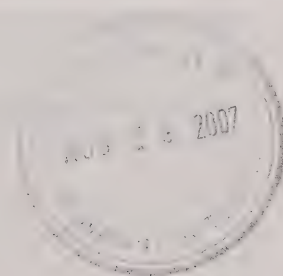


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CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT



JULY 2007

Canada

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ACRONYMS AND ABBREVIATIONS

AOS	Authorized Overrun Service
Alliance	Alliance Pipeline Ltd.
Altex	Altex Energy Ltd.
CAPP	Canadian Association of Petroleum Producers
CEPA	Canadian Energy Pipeline Association
Cochin	Cochin Pipe Lines Ltd.
Coral	Coral Energy Canada Inc.
DBRS	Dominion Bond Rating Service
EBIT	Earnings Before Interest and Taxes
Enbridge	Enbridge Pipelines Inc.
Express	Express Pipeline Limited Partnership
Foothills	Foothills Pipe Lines Ltd.
FT	Firm Transportation
FT-RAM	Firm Transportation Risk Alleviation Mechanism
GDP	Gross Domestic Product
Gateway	Gateway Pipeline Inc.
IGUA	Industrial Gas Users Association
Irving/Repsol	Irving Oil Company Limited and Repsol YPF
Kinder Morgan	Kinder Morgan Canada Inc.
LNG	Liquefied Natural Gas
M&NP	Maritimes & Northeast Pipeline Management Ltd.

Mackenzie	Mackenzie Gas Project
Moody's	Moody's Canada Inc.
NEB or Board	National Energy Board
NGL	Natural Gas Liquid
OEB	Ontario Energy Board
PADD	Petroleum Administration for Defense Districts
Petro-Canada	Petro-Canada Oil and Gas
PNGTS	Portland Natural Gas Transmission System
ROE	Return on Common Equity
S&P	Standard & Poor's
Terasen	Terasen Pipelines Inc.
T-South	Westcoast's Southern Mainline (Zone 4)
TNPI or	
Trans-Northern	Trans-Northern Pipeline Inc.
TPTM	Terasen Pipelines (Trans Mountain) Inc.
TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada or TCPL	TransCanada PipeLines Limited
U.S.	United States
Union Gas	Union Gas Limited
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc.

UNITS

b/d	Barrels per day
Mb/d	Thousand barrels per day
MMb/d	Million barrels per day
Bcf	Billion cubic feet
MMcf/d	Million cubic feet per day
GJ	Gigajoule
m ³ /d	Cubic metres per day
10 ³ m ³ /d	Thousand cubic metres per day

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency whose purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest¹ within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The NEB is an active, effective and knowledgeable partner in the responsible development of Canada's energy sector for the benefit of Canadians.

The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines, as well as tolls and tariffs. Another key role is to regulate international and designated interprovincial power lines. The Board also regulates the imports of natural gas and the exports of natural gas, oil, natural gas liquids (NGLs) and electricity. Additionally, the Board regulates oil and gas exploration and development on frontier lands and offshore areas not covered by provincial or federal management agreements. In its advisory function, the Board provides energy information and advice by analyzing information about Canadian energy markets obtained through regulatory processes and monitoring.

This report marks the third year that the Board has provided an assessment of the Canadian hydrocarbon transportation system. This report utilizes data from various publicly available sources which are collected and monitored by Board staff in addition to throughput data supplied by the pipeline companies. The Board also benefited from discussion with members of the investment community with respect to capital markets. Prior to the release of this report, a draft was sent to the Canadian Energy Pipeline Association (CEPA), the Canadian Association of Petroleum Producers (CAPP), and the Canadian Gas Association (CGA) for comment. Other parties such as the Industrial Gas Users Association (IGUA) also expressed interest and provided comment on the issues and aspects of information in this report. A listing of all organizations that provided comment or information in the production of this report is shown in Appendix 1. Comments by all parties were taken into consideration in the preparation of this report.

Any comments on the report or suggestions for further analysis can be directed to:

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Applications Business Unit
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Email: hmah@neb-one.gc.ca

If a party wishes to rely on material from this report in any regulatory proceeding, it can submit the material as can be done with any public document. In such a case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

Information about the NEB, including its publications, can be found by accessing the Board's website: <http://www.neb-one.gc.ca>.

¹ The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that changes as society's values and preferences evolve over time.

INTRODUCTION

Energy is essential to our daily lives. The ability of the pipeline transportation system to deliver energy, in the form of natural gas, natural gas liquids (NGLs), crude oil, and petroleum products is critical to Canada's economic well-being. In 2006, approximately \$110 billion worth of products was moved through Canadian pipelines to markets at home and in the U.S. The cost in 2006 of providing these transportation services is estimated to be around \$4.7 billion, not including the fuel costs paid by shippers on natural gas pipelines. This was accomplished by infrastructure that is mostly invisible to consumers and that operates safely with minimal environmental impact.

Canadians depend on this infrastructure for a safe, reliable, and efficient energy supply. The 45 000 kilometres (km) of natural gas and oil pipelines regulated by the NEB are a crucial element in Canada's hydrocarbon transportation system (Figures 1 and 2). These include large-diameter, cross-country, high-pressure natural gas pipelines, low pressure crude oil and oil products pipelines, and small-diameter pipelines.

In line with its mandate to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest, the Board has identified five goals which articulate its purpose and core directives²:

1. NEB-regulated pipelines and activities are safe and secure, and are perceived to be so.
2. NEB-regulated facilities are built in a manner that protects the environment and respects the rights of those affected.
3. Canadians benefit from efficient energy infrastructure and markets.
4. The NEB fulfills its mandate with the benefit of effective public engagement.
5. The NEB delivers quality outcomes through innovative leadership and effective support processes.

To determine whether the goals are being achieved, the Board has established various measures and a system of monitoring for each goal. Each year, the Board also issues various reports that discuss these different aspects of Canadian energy infrastructure and activities. This report focuses largely on aspects of Goal 3, and provides an update on the Board's assessment on how well the Canadian hydrocarbon transportation system is working. This report marks the third consecutive year for this assessment and utilizes the system of monitoring and measurements for the performance of the transportation system that was established in previous years. For the hydrocarbon transportation system to function efficiently and effectively, it must operate in a safe and environmentally acceptable manner, which relates to Goals 1 and 2. The Board also reports annually on safety, integrity, and environmental performance of NEB-regulated pipelines in a companion report that was published in March 2007, which may be found at <http://www.neb-one.gc.ca/clf-nsi/rsftyndthnvrnmnt/sfty/sftyprfrmncndctr/sftyprfrmncndctr-eng.htm>.

FIGURE 1

Gas Pipelines Regulated by the NEB



FIGURE 2

Oil Pipelines Regulated by the NEB



The Board believes that the following outcomes are important characteristics of a well functioning hydrocarbon transportation system:

- There is adequate pipeline capacity in place to move products to consumers who need them;
- Pipeline companies provide services that meet the needs of shippers at just and reasonable prices; and,
- Pipeline companies have adequate financial strength to attract capital on terms and conditions that enable them to effectively maintain their systems and build new infrastructure to meet the changing needs of the market.

In general, an efficient hydrocarbon transportation system will have an ability to respond on a timely basis to changing market conditions. This may entail adjustments to pipeline capacity or enhancement of pipeline services.

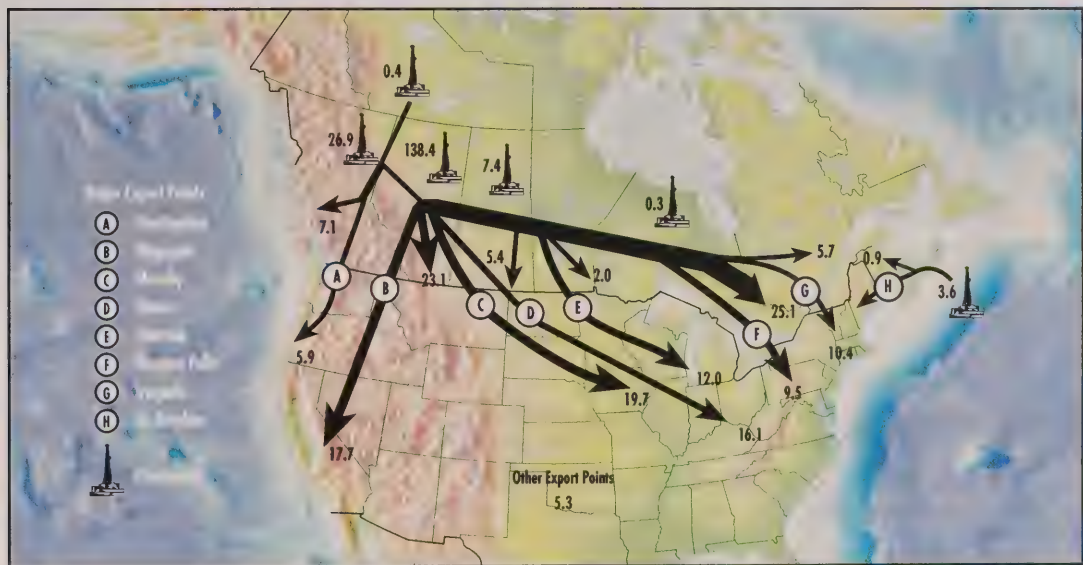
To assess the extent to which these outcomes are achieved, the Board uses publicly available data for Group 1 regulated companies and Express Pipeline Limited Partnership (Express), the largest Group 2 company.³ These companies represent the major NEB-regulated pipelines and provide a good view of the overall functioning of the hydrocarbon transportation system. In addition, the Board used throughput and capacity information received from the pipelines; discussions with members of the investment community; and input from the users of NEB-regulated pipelines. Although the majority of information presented in this report is an update and assessment for 2006; where available, 2007 information is also provided. A listing of the companies regulated by the NEB, as of December 31, 2006, can be found in Appendix 2.

This report should not be viewed as a regulatory decision. In this report the Board is not making a determination on regulatory matters such as the appropriate rate of return on equity that should be earned by pipeline companies. The factors used to assess the functioning of the transportation system are not necessarily the same as those which are applied in a regulatory proceeding.

Figures 3 and 4 provide an overview of the supply and disposition of natural gas and crude oil in Canada. More information on the supply and disposition of energy in Canada can be found in the Board's Energy Overview report, published in May 2007, which may be found at http://www.neb-one.gc.ca/energy/EnergyReports/index_e.htm#energy_overview.

FIGURE 3

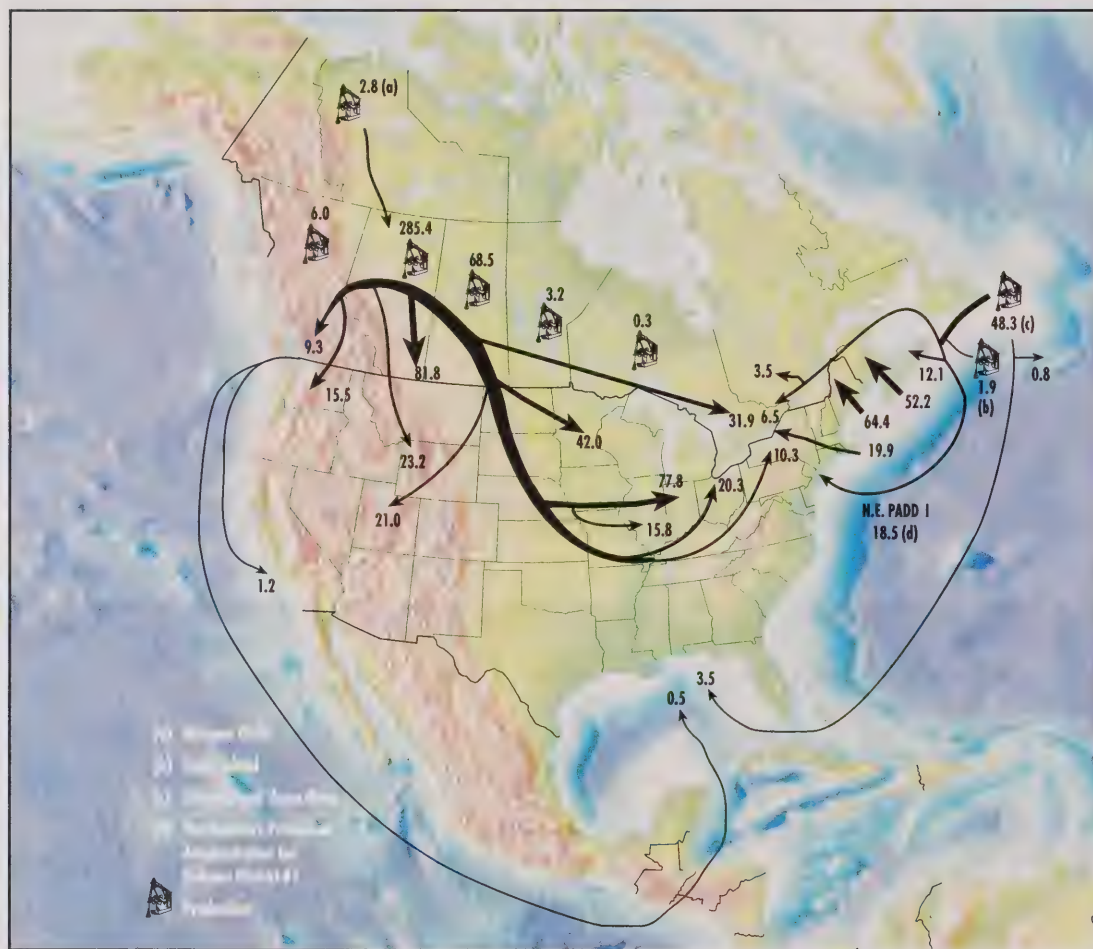
**2006 Supply and Disposition of Natural Gas
(Billion Cubic Metres)**



3 For the purpose of the Board's financial regulation, pipeline companies are divided into two groups, Group 1 and Group 2. Major oil and gas pipeline companies are designated as Group 1 and are generally actively regulated by the NEB. All other NEB-regulated pipelines are designated as Group 2 and are subject to a lighter degree of regulation.

FIGURE 4

**2006 Supply and Disposition of Oil
(Thousand cubic Metres per Day)**



ADEQUACY OF PIPELINE CAPACITY

A key measure of an energy market's operational efficiency is the ability of its pipeline system to adequately transport crude oil, refined products, natural gas and natural gas liquids (NGLs) from producing to consuming regions.

This section will examine the following factors to assess the current adequacy of pipeline capacity:

1. price differentials compared with firm service tolls for major transportation paths;
2. capacity utilization on pipelines; and
3. the degree of apportionment on major oil pipelines.

The Board has generally taken the view that some excess capacity on a pipeline is desirable. This may result in higher tolls for shippers; however, the costs associated with inadequate pipeline capacity can be far greater. Substantial revenue loss for producers and governments can result when producers are unable to move their oil and gas to market. In addition, excess capacity allows shippers the flexibility to access the appropriate markets with the right product, thereby maximizing their revenues.

For example, in the case of oil transportation, if there is inadequate pipeline capacity to transport crude oil to the West Coast (PADD V), producers have the option of transporting crude oil to Ontario, PADD II (Midwest), southern PADD II (Cushing, Oklahoma), PADD III (U.S. Gulf Coast) or PADD IV (Rockies). As well, during periods when refineries are in turnaround (maintenance) in any of these locations, producers can deliver crude oil volumes to other markets, providing there is adequate pipeline capacity.

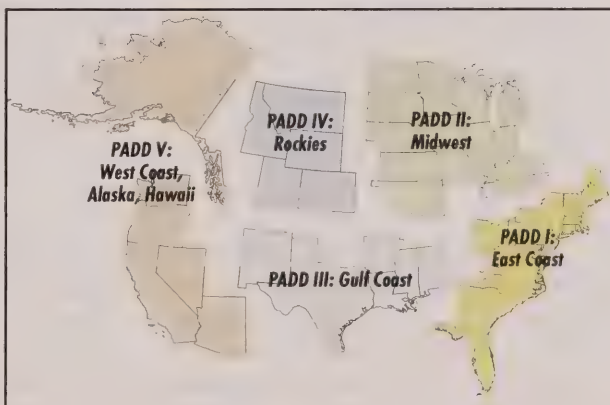
2.1 Price Differentials

Price Differentials and Natural Gas Firm Service Tolls

When there is adequate pipeline capacity between two market hubs, commodity prices will be connected and the price differential will be equal to, or less than, the transportation costs between the two points. As long as the price differential is less than the toll plus fuel, the market is indicating that there is adequate pipeline capacity between the two pricing points. In a market with adequate capacity, suppliers would generally direct their product to the

FIGURE 5

Petroleum Administration for Defense Districts



market that nets the highest revenue back to the seller, thereby meeting that region's need for energy. Where inadequate capacity exists, the product cannot get to market, resulting in higher prices for downstream consumers or lower prices to producers, creating a higher differential in price between the two end points.

In order to use price differentials as an indicator on the adequacy of pipeline capacity, there must be reasonably good pricing data available. Two examples of price differentials compared with firm service tolls are provided below – one for transportation on TransCanada PipeLines Limited Mainline (TransCanada or TCPL) and one for transportation on Westcoast Energy Inc. (Westcoast).

Figure 6 shows the basis differential between Alberta and the Dawn delivery point compared with the TransCanada firm service toll between the two points, including fuel costs. The price differential between Alberta and the Dawn delivery point is generally below the total cost of transportation (firm transportation plus fuel) via the TransCanada pipeline connecting these two markets. This indicates that pipeline capacity is adequate between these locations. As indicated by the variation in the price difference between the two locations, natural gas pricing is very responsive to relatively small changes in flow or demand. Times of exceptional natural gas demand in eastern markets, such as the summer heat waves of 2005 and 2006 that produced a strong demand for natural gas-fired power generation for air conditioning in eastern markets, or reduced supplies from the Gulf of Mexico in the months following hurricanes Katrina and Rita (August 2005 to January 2006), have resulted in short term increases in the price differential. Conversely, mild weather and ample gas in storage can moderate the price differential and the demand for gas and transportation services such as occurred in the autumn of 2006 and the early part of the 2006/2007 winter heating season.

Figure 7 shows the price differential between Compressor Station 2 on the Westcoast system and the export point at Huntingdon/Sumas compared with the firm service toll for transportation between the two locations (T-South or Southern Mainline), including fuel costs. Since January 2003, except for the peak winter months in recent years, the price differential has been lower than the cost of transportation, indicating that there has been adequate capacity in place. Overall, the comparison of price differential and natural gas firm service tolls shows that pipeline capacity between these markets is adequate at most times. However, natural gas pricing is volatile. Short-term increases in the price differential have been observed in recent years as a result of changes to market conditions such as,

FIGURE 6

Dawn – Alberta Price Differential vs. TransCanada Toll and Fuel

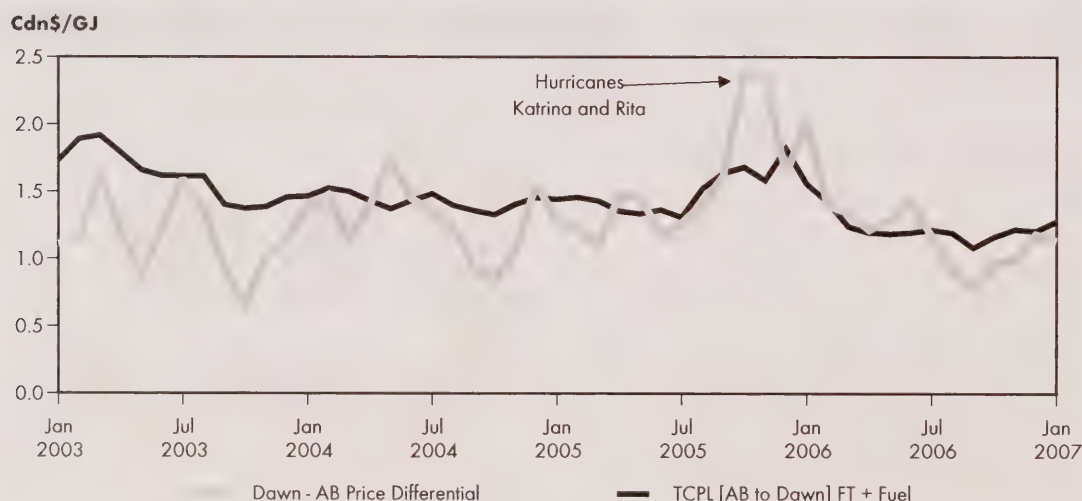
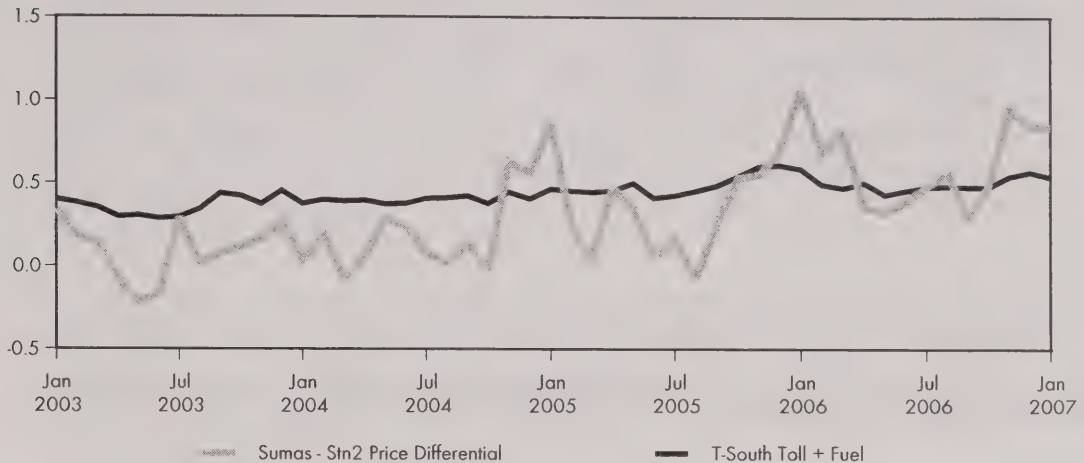


FIGURE 7**Sumas – Station 2 Price Differential vs. Westcoast T-South Toll and Fuel****Cdn\$/GJ**

hurricane-induced supply disruptions in the United States, unpredictable weather-related demand, and availability of other transportation options during such periods.

Overall, the comparison of price differentials and natural gas firm service tolls shows that pipeline capacity between these markets is adequate at most times. In general, the price differential between pricing points has been slightly lower than the cost of pipeline transportation (tolls) and fuel. However, natural gas prices can fluctuate in response to weather and can impact both price differential and pipeline fuel costs. Pipeline tolls tend to be more constant. Figures 6 and 7 both indicate occasions where the price differential exceeded transportation (toll) and fuel costs. These events proved to be temporary, and gas flows and prices moderated.

Price Differentials and Tolls on Oil Pipelines

The price differentials for crude oil are determined by a number of factors, including availability of pipeline capacity, supply and demand fundamentals, seasonality and the grade (quality) of crude oil. Price differentials are increasingly becoming an issue on oil pipelines because of increasing production from the oil sands. Oil sands crude oil is a heavier bitumen blend and has limited market access because it requires specially equipped refineries to process it into useable refined products. This limited access exerts downward pressure on heavy crude oil prices and widens the light-heavy differential during certain times of the year. Historically the discussion on price differentials have been exclusive to heavy crude oil; however, with increased production of upgraded bitumen or light synthetic crude oil - the price differential between synthetic crude oil, Canadian light crude oil, and other crude oil supplied to U.S. refineries is becoming an increasingly important issue. Largely as a result of increased synthetic crude oil production and limited pipeline capacity to downstream markets, price discounts have also been observed for Canadian synthetic and light crude oil.

Figure 8 illustrates the light-heavy differential as indicated by the difference in the price of Edmonton Par light crude oil and Western Canadian Select (WCS), a heavy crude oil blend that is priced at Hardisty, Alberta. As illustrated, the differential between them has been wide and volatile during the time period shown; however, there has been a narrowing trend since September 2006. In the first quarter 2007, the light-heavy differential was 27 percent. In particular, in the month of March, the light-heavy differential narrowed to its lowest level since August 2004. There are two main reasons

FIGURE 8**Canadian Crude Oil Prices and Differential**

for this narrowing; one is the Syncrude upgrader expansion, which is processing more bitumen, up to 350 Mb/d per day from 240 Mb/d in 2006; the second is the Spearhead and Mobil pipeline reversals which are transporting almost 200 Mb/d of crude oil south of Chicago to as far as the U.S. Gulf Coast. Typically, during the summer months, the differential narrows because of an increase in seasonal demand for heavier crudes for the production of asphalt.

2.2 Capacity Utilization on Major Routes

Where adequate pricing data is not available at major receipt and delivery locations on pipeline systems, another measure of adequate capacity comes from directly comparing the throughput or flow on the pipeline with its capacity. The Board monitors capacity utilization for most of the large pipelines it regulates.

The following figures show pipeline average monthly throughput compared with capacity for some of the largest NEB-regulated pipeline systems, including the TransCanada Mainline, Foothills Pipe Lines Ltd. (Foothills), TransCanada B.C. System, Westcoast, Alliance Pipeline Ltd. (Alliance), Trans Québec & Maritimes Pipeline (TQM), Maritimes & Northeast Pipeline (M&NP), Enbridge Pipelines Inc. (Enbridge), Kinder Morgan Canada's Terasen Pipelines (Trans Mountain) Inc. (TPTM), Express and Trans-Northern Pipeline Inc. (TNPI).

Natural Gas

Figure 9 compares the average monthly throughput on the TransCanada Mainline (which is approximately equal to the amount of gas flowing east on the Mainline from Saskatchewan) to the capacity of TransCanada's prairie line. This comparison illustrates that there has consistently been capacity in excess of throughput volumes over the time period shown. The excess capacity even persisted through the period of July 2005 to July 2006, which included two hotter-than-normal summers that produced strong demand for natural gas for power generation in eastern markets, and greater demand for Canadian gas due to production losses in the U.S. stemming from the late summer hurricanes of 2005.

On the eastern part of the TransCanada system, a number of expansions occurred in 2006 or are proposed for 2007 which are directed towards reducing bottlenecks to connect additional supply from Dawn and to access growing markets in Eastern Canada and the U.S. Northeast.

Overall, the indicator shows that there has been adequate pipeline capacity to move volumes to eastern markets. Excess capacity, which averaged 1.4 Bcf/d over the past four years, provided the impetus for the TransCanada Keystone Pipeline project. In this initiative, TransCanada proposes to transfer Line 100-1 of the Mainline to TransCanada Keystone Pipeline GP Ltd. for conversion to oil service. This transfer and conversion, if approved, could result in an annual average capacity reduction on the Mainline of approximately 0.5 Bcf/d. The Board approved the facilities transfer on 9 February 2007, however the TransCanada Keystone application for the construction of the requested oil facilities is still before the Board.

The volumes shown in Figure 10 are the average monthly throughput on TransCanada's Foothills Pipeline (Sask.) compared with capacity. This pipeline transports western Canadian gas supply to

FIGURE 9

TransCanada Mainline Throughput vs. Capacity

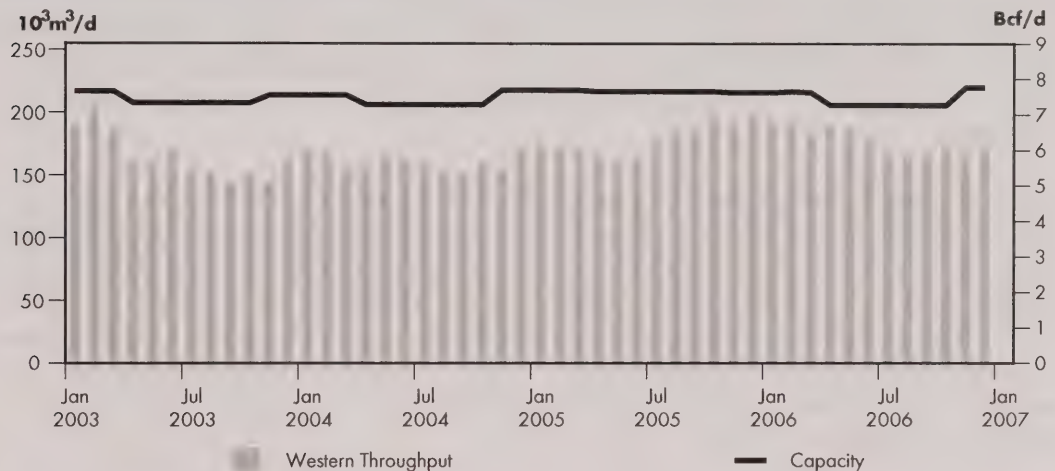
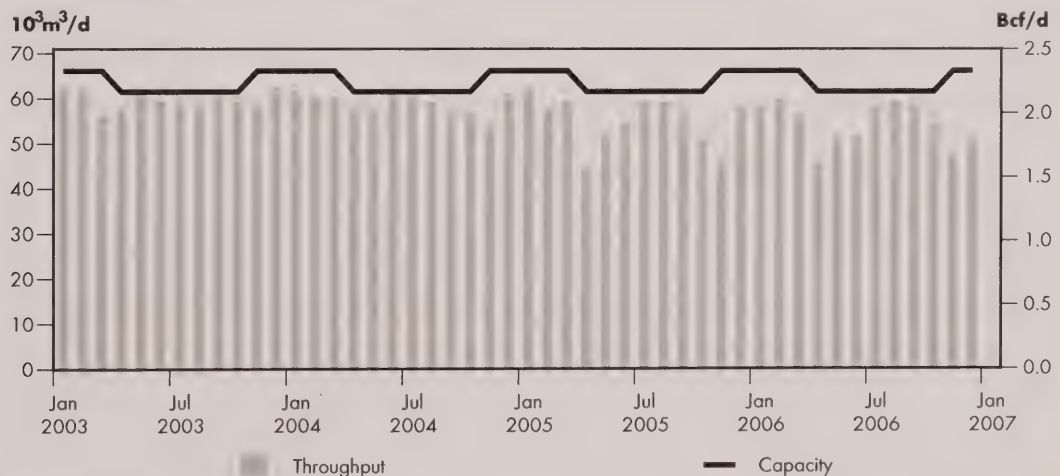


FIGURE 10

Foothills Pipeline (Sask.) Throughput vs. Capacity at Monchy



markets in the U.S. Midwest through a connection with the Northern Border Pipeline Ltd. (Northern Border) at Monchy, Saskatchewan. The Foothills (Sask.) throughput has displayed distinct seasonal patterns in recent years, with annual average capacity utilization running at 88 percent in 2006, down from an average of 94 percent in 2003. Throughput on the Foothills Pipeline (Sask.) runs fairly close to capacity in both the winter and the summer months to meet winter heating demand and to meet summer demand for power generation and storage injection. Throughput subsequently declines in the low-consumption spring and autumn months.

Figure 11 compares the average monthly throughput on Westcoast's Southern Mainline with the capacity on this system between Station 2 and the export point at Huntingdon/Sumas. This figure shows the seasonal nature of throughput on the Southern Mainline with higher volumes being transported during the peak winter months and less during the summer. Contributing factors to the low flows on Westcoast during 2006 and recent years include greater competition with production from the U.S. Rockies region for markets in the U.S. Pacific Northwest, mild winter weather, and increased hydro power generation in B.C. and the U.S. Pacific Northwest.

Figure 12 shows the average monthly capacity and throughput on the TransCanada B.C. System, which primarily serves California. The annual average capacity utilization in 2006 was 64 percent, slightly higher than in previous years. There exists spare capacity on this pipeline to export gas through Kingsgate, B.C. California market players have transportation options enabling them to access supply from the Rocky Mountains, San Juan and Permian basins, in addition to the Western Canada Sedimentary Basin (WCSB). This supply competition has reduced imports from the WCSB at Kingsgate.

Figure 13 shows the average monthly throughput on the Alliance system relative to physically available capacity. Alliance offers approximately 1.325 Bcf/d of firm service capacity, and makes any additional capacity available to its contracted shippers pro rata as Authorized Overrun Service (AOS). Available AOS levels are determined on a daily basis and may be used at the cost of fuel only. The total available capacity is variable, depending on such factors as ambient temperature and compressor unit availability (as influenced by maintenance schedules). Alliance's total available capacity has essentially been fully utilized since the commencement of service, with all available firm service contracted on a long-term basis.

FIGURE 11

Westcoast Mainline Throughput vs. Capacity

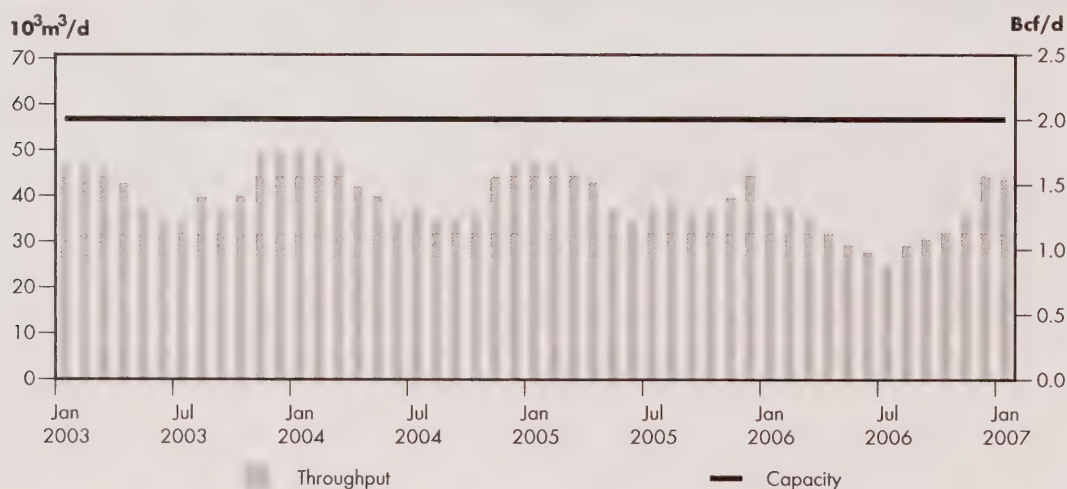


Figure 14 compares the average monthly throughput and capacity on the TransQuébec & Maritimes system (TQM) which delivers gas from the TransCanada Mainline at Saint-Lazare, Quebec to Québec City and the East Hereford export point in Quebec (New Hampshire state border). More volumes are transported during winter months, highlighting the use of natural gas for heating in this region and the seasonal nature of the throughput on this pipeline. With average annual capacity utilization of around 60 percent, there has historically been spare capacity on this pipeline, particularly in summer months. However, with the limited compression on the system needed to meet TQM's delivery pressure at the East Hereford export point, the available spare capacity is very sensitive to the actual load distribution on the pipeline. In 2006, TQM undertook a system expansion to serve an incremental demand arising from the construction of a new gas-fired power plant in Quebec.

Figure 15 compares the average monthly capacity and throughput on the M&NP pipeline. The annual average capacity utilization has declined from about 92 percent in 2002 to an average of about 68 percent in 2006. The reduction in this pipeline's capacity utilization stems from declining natural

FIGURE 12

TransCanada B.C. system Throughput vs. Capacity at Kingsgate

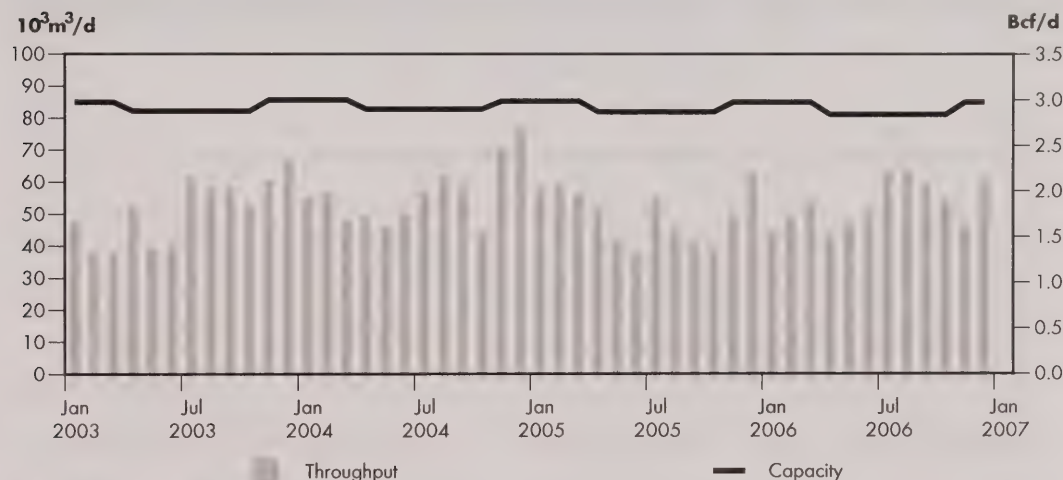


FIGURE 13

Alliance Throughput vs. Capacity

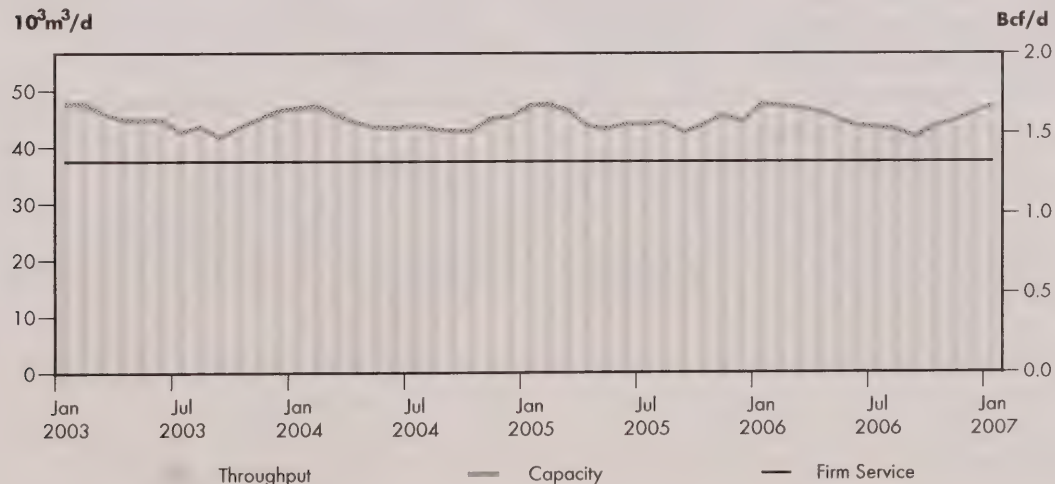
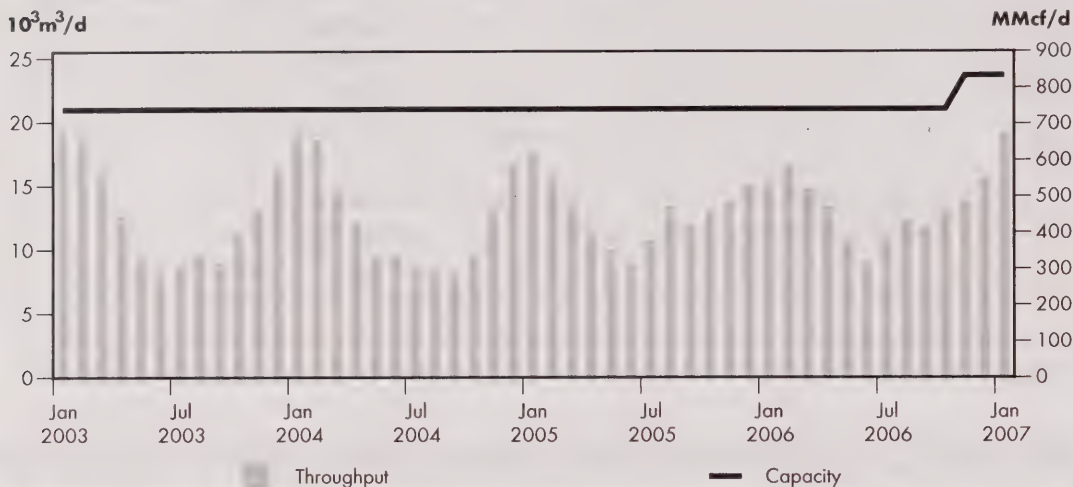
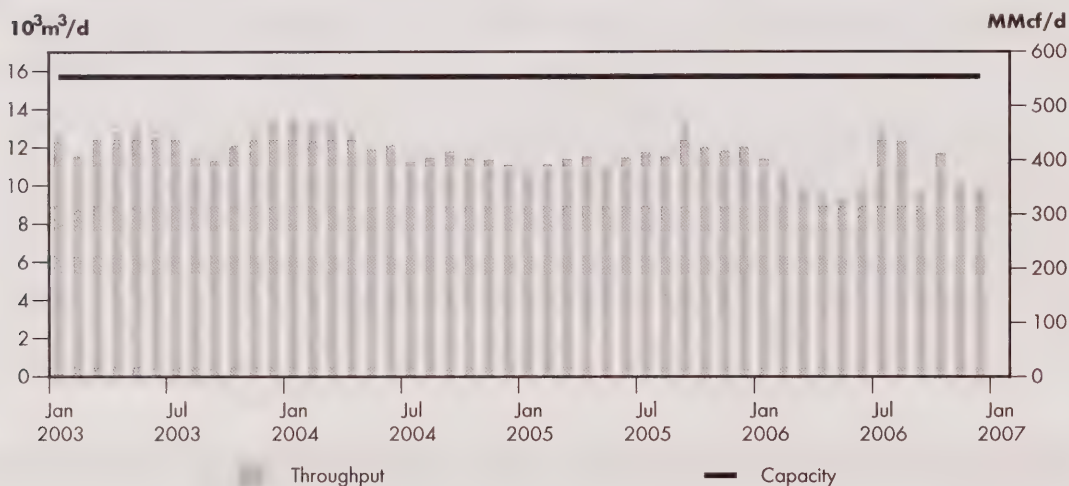


FIGURE 14**Trans Québec and Maritimes Throughput vs. Capacity****FIGURE 15****Maritimes and Northeast Pipeline Throughput vs. Capacity**

gas production from offshore Nova Scotia. Variations in throughput are primarily related to changes in gas supply as the export demand for gas destined to northeastern U.S. markets is consistently strong. In late 2006, additional compression at the offshore platform was installed to boost deliverability. In addition, a couple of gas supply projects are being considered in the region with the potential to supplement supply.

Oil

Determining the capacity and throughput on an oil pipeline can be complex as there are many factors to be considered: the type of product, product mix, type of batching and pipeline configurations.

The Enbridge system originates in Edmonton, Alberta and extends east across the Canadian prairies to the U.S. border near Gretna, Manitoba where it joins with the Lakehead system in the U.S. It is the largest crude oil pipeline in the world and the primary transporter of crude oil from western Canada to markets in eastern Canada and the U.S. Midwest. The Enbridge system also connects

with pipelines that deliver crude oil to Cushing, Oklahoma and the U.S. Gulf Coast. The system consists of many lines transporting crude oil, NGLs and refined petroleum products. Figure 16 illustrates Enbridge throughput versus capacity. In 2006, Enbridge transported roughly 247 000 m³/d (1.6 MMb/d) of crude oil, petroleum products and NGLs. In the first quarter 2007, Enbridge operated at about 85 percent of capacity. Since the third quarter of 2006, many of its lines have been operating at or near full capacity with some lines in apportionment (see Section 2.3).

Terasen Pipelines (Trans Mountain) Inc., owned by Kinder Morgan, transports crude oil and refined petroleum products from Edmonton, Alberta west to locations in British Columbia, Washington State and offshore. TPTM's current capacity, assuming some heavy crude oil, is 35 700 m³/d (225 Mb/d). The pipeline has been operating at or near capacity for several years and on many occasions has been under apportionment (See Section 2.3). Figure 17 shows two capacities for the TPTM pipeline; one assumes no shipments of heavy crude oil and the other assumes 15 percent heavy crude oil. When heavy crude oil is shipped, it reduces the capacity of the pipeline. On average, in 2006, 15 percent of TPTM's crude oil receipts at Edmonton were heavy crude oil. In the second quarter of 2007, the TPTM Pump Station Expansion is expected to be in-service. It will add an additional 5 600 m³/d (35 Mb/d) of capacity.

In February 2006, TPTM applied to the NEB to loop a 158 km segment of its pipeline, extending from Hinton, Alberta to a location near Rearguard, British Columbia. The Project would increase capacity by 6 360 m³/d (40 Mb/d). An oral public hearing was held in August 2006 and the Board approved the application in October. The targeted in-service date is the fourth quarter 2008.

In the first quarter of 2007, TPTM operated at approximately 77 percent of capacity (see Figure 17). Despite operating at below its nameplate capacity of 285 Mb/d, TPTM was under apportionment in January and February of 2007. Growing oil sands production, strong demand from refiners in Washington State and continuing growth in crude oil shipments off the Westridge Dock are contributing to apportionment on the TPTM system. As well, in the summer of 2006, a temporary shutdown of the Prudhoe Bay field in Alaska, because of pipeline corrosion, resulted in increased throughput on the TPTM pipeline.

During the past several years, Express has been operating at capacity. Despite a major expansion in 2005 that added 16 000 m³/d (100 Mb/d), bringing the capacity to 44 900 m³/d (280 Mb/d) there has

FIGURE 16

Enbridge Pipeline Throughput vs. Capacity

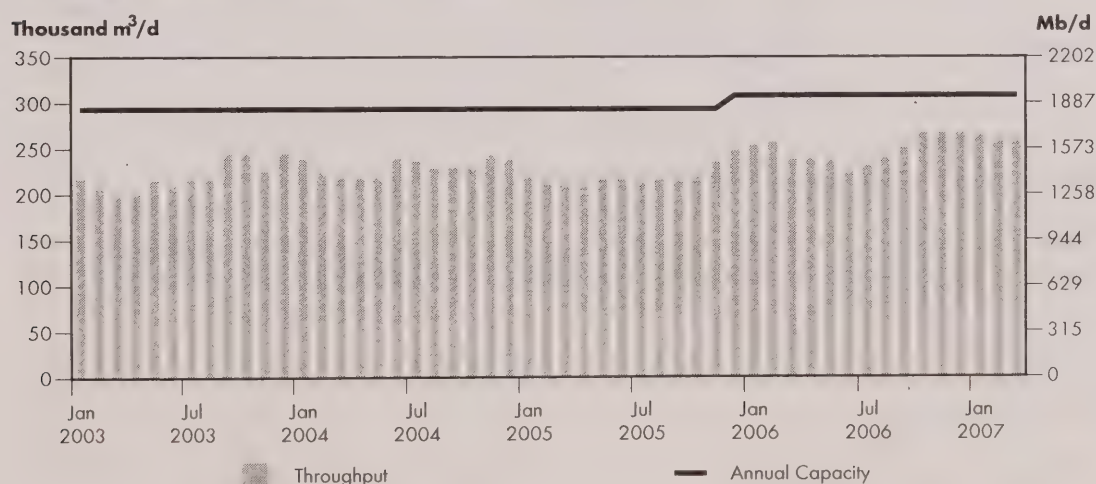


FIGURE 17

Teresen Pipelines Trans Mountain (TPTM) Throughput vs. Capacity

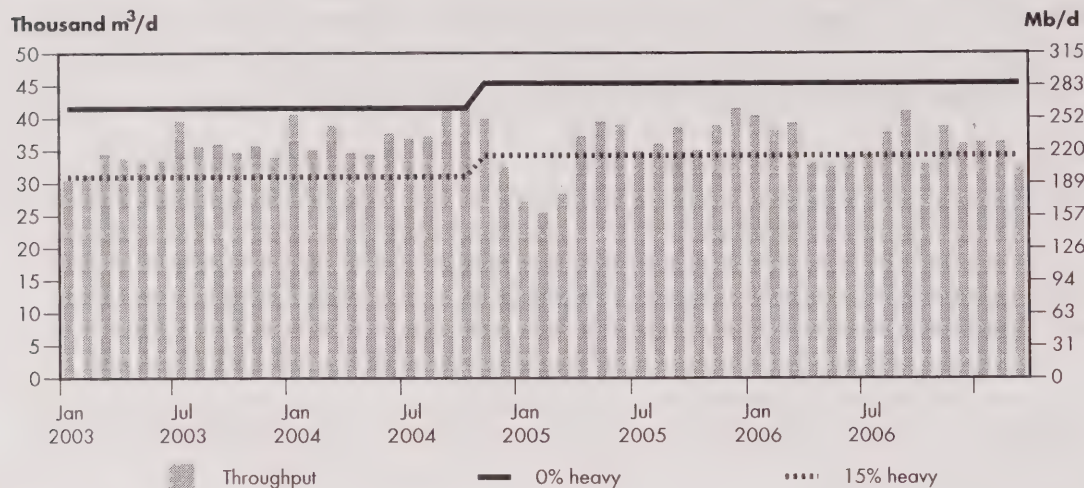
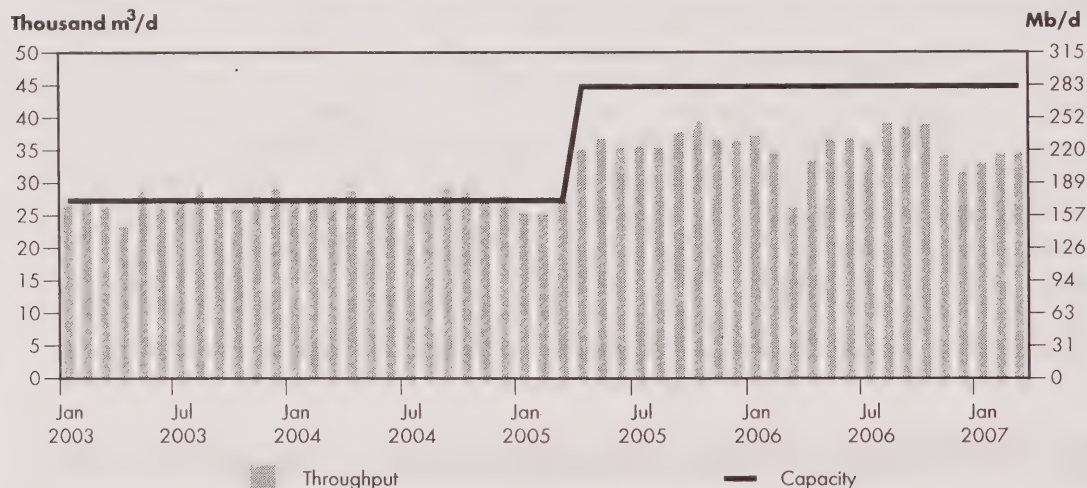


FIGURE 18

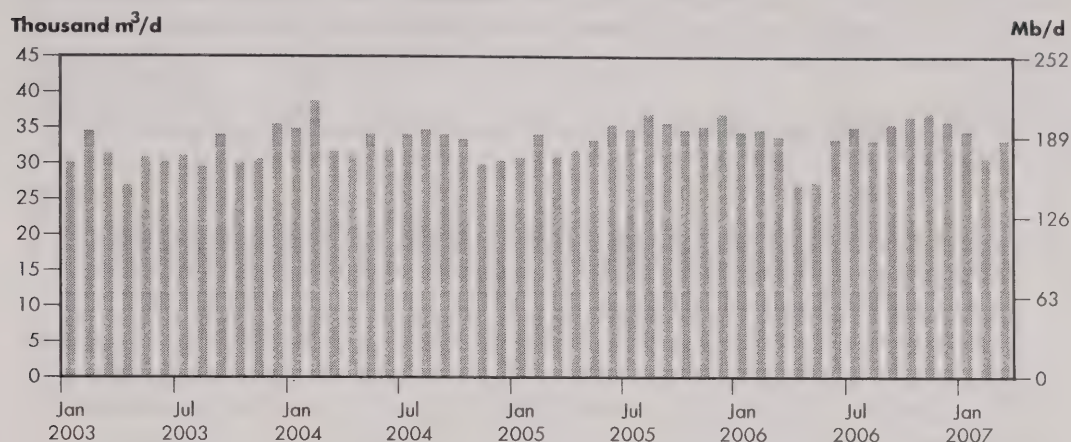
Express Throughput vs. Capacity



been apportionment on the pipeline in 2006. Express is the only crude oil pipeline in western Canada that operates under long-term take-or-pay agreements with its shippers for a majority of its capacity.

In the first quarter 2007, Express operated at approximately 76 percent of capacity (Figure 18). Crude oil shipments have been reduced at Hardisty on the Express pipeline because of continuing apportionment downstream on the Platte Pipeline in the U.S.

Trans-Northern Pipelines Inc. is a refined petroleum products pipeline. The pipeline transports refined petroleum products west from Montreal to north Toronto and operates bi-directionally between Toronto and Oakville, Ontario. TNPI also transports refined products from Imperial Oil Limited's (Imperial) refinery in Nanticoke, Ontario west to Toronto. In the first quarter of 2007, TNPI throughput averaged 33 000 m³/d (208 Mb/d) of petroleum products. The pipeline is generally operating at capacity.

FIGURE 19**Trans-Northern Pipelines Inc. Throughput**

During the first quarter 2007, there was a fire at Imperial's refinery located in Nanticoke. This resulted in the refinery ceasing operations and a subsequent gasoline and diesel shortage in southern Ontario and Quebec. TNPI throughput was reduced during this period.

Calculating TNPI's capacity is difficult due to multiple delivery locations and the different capacities on each line segment.

2.3 Apportionment

Oil pipelines typically operate as common carriers. Common carriers require shippers to nominate their volumes for delivery into a pipeline on a monthly basis without a contract for pipeline capacity. When shippers nominate more oil or oil products in a given month than the pipeline can transport, shippers' volumes are apportioned (reduced) based on the tariff in effect. Apportionment can be caused by factors such as growing supply, increased demand, pipeline reconfigurations and refinery maintenance. There are a few pipelines in Canada that operate all or part of the pipeline with long-term shipper take-or-pay agreements, including Express, Enbridge Line 9 and TNPI.

Some recent apportionment levels for Enbridge, TPTM and Cochin are discussed below.

Enbridge

Enbridge's Lines 3 and 4 are dedicated to transporting heavy crude oil and Line 2 transports light crude oil. Historically, Lines 2 and 4 were heavy crude oil lines; however, following the Line 2/3 line swap in the fourth quarter 2005, Line 2 transitioned from a heavy crude oil line originating at Hardisty, Alberta to a light crude oil pipeline originating in Edmonton. In addition, Line 3 made the transition from a light crude oil pipeline originating at Edmonton to a heavy crude oil pipeline originating at Hardisty. This swap resulted in a net heavy capacity increase of 39 000 m³/d (246 Mb/d) and a corresponding decrease of light capacity of 18 400 m³/d (116 Mb/d). This added some much needed capacity to accommodate growing heavy crude oil output from the oil sands.

Table 1 indicates apportionment and throughput from August 2006 to March 2007. In the fourth quarter 2006, throughputs were very high on the Enbridge system and there was apportionment on Lines 5, 6 and 14. There has not been apportionment on the Enbridge system in the first quarter 2007; however, many of the Lines have been either fully subscribed or operating at maximum capacity.

TABLE 1

Enbridge Apportionment

	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07
Apportionment	0%	0%	0%	0%	8%*	0%	0%	0%
Throughput (10 ³ m ³ /d)	240.7	251.0	266.3	266.8	266.7	263.6	258.9	259.7

* Lines 5, 6 and 14

Capacity is also constrained due to a downstream bottleneck at Superior, Wisconsin because the capacity out of Superior is 230 000 m³/d (1.4 MMb/d), less than the up to 300 000 m³/d (1.9 MMb/d) that Enbridge can deliver to that destination.

Enbridge throughput fell slightly in the second quarter 2006 as a result of outages at two oil sands plants. In the third quarter 2006, throughput increased reflecting capacity expansions and increases in oil sands production. In addition, competitively priced western Canadian crude oil displaced some import volumes that would typically be delivered to the Sarnia area on Enbridge's Line 9. It is expected that increasing production from the oil sands in 2007 could contribute to further apportionment on Enbridge.

Enbridge's Line 9 has a capacity of 38 150 m³/d (240 Mb/d) and transports crude oil from Montreal, Quebec to refineries located at Nanticoke and Sarnia, Ontario. There was no apportionment on Line 9 between August 2006 and February 2007. Shipments on Line 9 have been trending downward, particularly since the closure of Petro-Canada's refinery in Oakville in the second quarter of 2005. In 2006, the reduction in throughput was a result of maintenance activity at Imperial's Sarnia refinery in the second quarter and an increase in deliveries of more competitively priced western Canadian crude oil.

In January 2007, Enbridge Pipelines (Westspur) Inc. applied to the National Energy Board pursuant to section 52 of the *National Energy Board Act* (NEB Act), for the Alida, Saskatchewan to Cromer, Manitoba Capacity Expansion Project. The Enbridge Westspur pipeline was built in 1956 as an oil trunkline to transport crude oil. The pipeline also transports NGL from a gas processing plant in Steelman, Saskatchewan. Westspur interconnects with the Enbridge export lines at Cromer where the crude oil accesses the downstream markets.

The project proposes to construct a new 60 km, 168.3 mm (6 inch) pipeline to transport NGL from Alida to Cromer and convert the existing pipeline from its current NGL service to crude oil. Capacity on the existing line would increase from 25 000 m³/d (157 Mb/d) to 34 600 m³/d (218 Mb/d).

Terasen Pipelines (Trans Mountain) Inc.

Apportionment on TPTM is calculated separately for domestic destinations, export destinations and Westridge Dock destinations (as shown in Table 2 as Domestic, Export and Dock). Apportionment between August 2006 and March 2007 reflects continuing increases in oil sands supply and strong demand for Canadian crude oil in the Washington State area. In addition, increases in heavy crude oil shipments, result in a decrease in the capacity on the TPTM system. With weakness in the price of West Texas Intermediate (WTI) and discounting of Canadian crude oil because of over-supply in the Cushing area, coupled with a lack of take away capacity in that region, producers may increasingly look to the higher priced west coast and offshore markets for improved netbacks.

TABLE 2**TPTM Apportionment**

	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07
Apportionment								
Domestic	0%	8%	0%	14%	35%	22%	10%	0%
Export	0%	0%	0%	0%	12%	0%	0%	0%
Dock	0%	0%	0%	0%	0%	0%	0%	0%
Throughput (10 ³ m ³ /d)	37.6	41.0	32.9	38.6	35.9	36.2	36.3	32.4

In April 2006, the NEB approved a request from Kinder Morgan Inc. to include a Westridge Dock Premium in the TPTM tariff to allocate capacity to the Westridge Dock. In the Board's decision, it directed Kinder Morgan to set up a deferral account for any premiums received and refund the money to toll payers in the following calendar year. The Board directed Kinder Morgan to publish the aggregate bid premium information on a quarterly basis; and, it approved the extension of the bid premium process until the start-up of the pump station expansion (PSE).

Cochin

In January 2007, Kinder Morgan Energy Partners purchased the remaining approximately 50 percent of Cochin Pipeline that they did not already own from BP Canada Energy Company (BP). Prior to the purchase, BP operated the pipeline and owned a slight majority stake.

The Cochin pipeline is the largest and longest NGL pipeline in Canada. In the past, it has transported propane, ethane, ethylene and butane, although no butane has been shipped since 2002. Ongoing maintenance work on the pipeline has affected the available capacity; however, (Table 3) there has not been apportionment on Cochin since summer 2005 when the pipeline was forced to unexpectedly shutdown for immediate repairs.

Since March 2006, Cochin has operated at a voluntary pressure reduction due to a defect found in the U.S. portion of the pipeline. This pressure restriction, not to exceed 900 psi, applies to the entire line from Fort Saskatchewan, Alberta to Windsor, Ontario and is in effect through at least to the fall of 2007. Ethylene shipments, because of its high vapour pressure, have been suspended until further notice.

Cochin also announced on 8 February 2007 that it would be suspending delivery of ethane effective 31 March 2007, while the company evaluates its pipeline integrity issues and the related capital expenditures. Cochin will continue to ship propane to all destinations on its system. Shippers were also informed that the pipeline would operate at reduced pressure through at least Fall 2007. With only propane in the line, the average capacity is expected to be around 9 500 to 11 100 m³/d (60 Mb/d to 75 Mb/d). Once the pressure restrictions are lifted, capacity is likely to return to 16 700 m³/d (105 Mb/d).

TABLE 3**Cochin Apportionment**

	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07
Apportionment	0%	0%	0%	0%	0%	0%	0%	0%
Throughput (10 ³ m ³ /d)	7.6	5.6	9.5	7.6	10.9	7.7	7.4	6.5

2.4 Chapter Summary

Overall, the examination of throughput and capacity on NEB-regulated natural gas pipelines in section 2.2 shows that pipeline capacity is adequate across the country although there may be occasions of short-term limitation at some points depending upon markets, storage and seasonal shifts. The demand for natural gas varies seasonally and, as a result, the flow of natural gas and utilization of some Canadian pipelines can be variable. Where available, the use of storage helps to reduce the variation in flows and allows pipeline capacity to be used more efficiently and at more stable utilization levels.

Although natural gas supply from new sources continue to be added to supplement declining conventional supply from the WCSB, growing demand within Western Canada has resulted in some excess capacity on pipelines transporting gas from the region. The existence of some excess capacity has provided suppliers with the flexibility to access markets of their choice at most times. Natural gas pipeline projects in 2006 were mainly directed towards providing connection to new supplies and addressing bottlenecks in the market area.

While capacity utilization indicators show that there was spare capacity on some oil and petroleum products pipelines in 2006, this was partially due to facility outages reducing the amount of crude oil or products to be transported. Despite operational challenges in the oil sands industry in early 2006, bitumen production levels have increased over the previous year as problems were rectified and new expansions were brought on-line. The production growth in the oil sands and continued strong demand in the U.S. has resulted in very high utilization of capacity on Canadian oil pipelines. In addition, a slight recovery in conventional crude oil production in western Canada, North Dakota and PADD IV are challenging pipeline systems that operate at close to capacity and are in apportionment at times. Overall, growing oil sands production has kept the utilization and demand for oil pipeline capacity very high.

In the past, the lack of excess pipeline capacity and available markets to process heavier crude oil has resulted in the light-heavy price differential widening as illustrated in Figure 8. In the first quarter 2006, the differential widened to 42 percent. However, this has not been the case in 2007, where the differential has narrowed to a two and a half year low reflecting the effect of additional markets accessed through the Syncrude upgrader expansion and the Spearhead and Mobil pipeline reversals which deliver western Canadian crude oil to Cushing and the U.S. Gulf Coast, respectively. This should provide continuing strength to heavy crude oil prices through the summer as demand will increase in response to the upcoming asphalt season.

LOOKING AHEAD – PROPOSED PIPELINES

3.1 Natural Gas

In the coming years, it is expected that demand for natural gas in North America will continue to outpace the growth in North American domestic supplies. In Canada, natural gas supply from new sources such as frontier regions, LNG, and coalbed methane will be increasingly required to supplement declining supply from conventional sources from the WCSB and Sable Island to meet growing demand. In addition, increased consumption for oil sands development in Alberta, and electricity generation in Ontario, are expected to drive significant incremental Canadian requirements for natural gas. The Canadian oil sands projects are a large and growing market for natural gas in both the generation of electricity and steam. Steam is used for in situ oil production and to upgrade bitumen into synthetic blends. In addition, new gas-fired electrical generation will likely be needed to help displace the use of existing coal-fired electricity generation in Ontario.

Although there were few newly announced natural gas pipeline projects in 2006, there was notable progress in several of the natural gas pipeline projects reported last year. Table 4 below, summarizes the announced proposals on NEB-regulated pipelines. These projects reflect the industry's expectations regarding changes in natural gas supply and demand in coming years, and the industry's outlook on the potential adjustments in Canadian pipeline infrastructure in order to:

- connect incremental gas supply from new sources in the north or from new terminals for receiving liquefied natural gas;
- expand pipeline capacity to growing markets in eastern Canada and the U.S. Northeast; and
- transfer pipeline assets from gas service where adequate capacity may exist, to oil transportation service where demand and value for new capacity is higher.

Liquefied Natural Gas

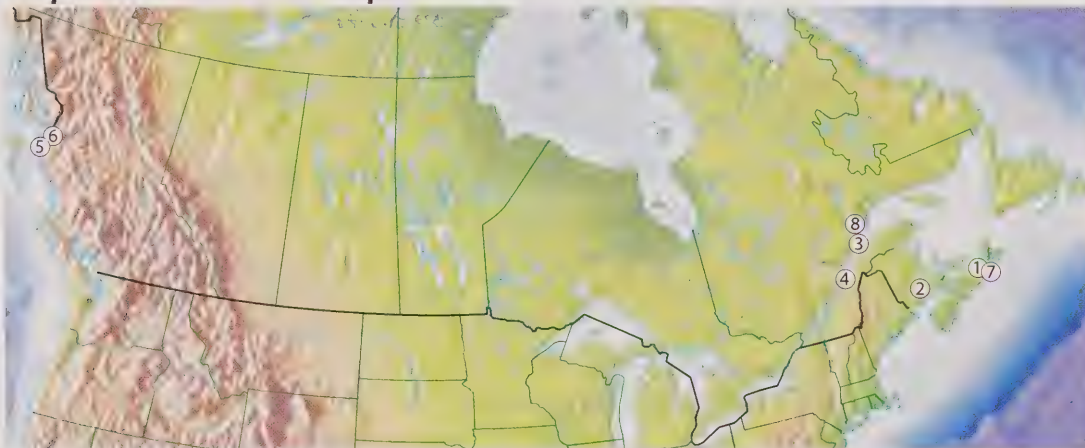
A key supply source for North America is expected to be the rapidly developing global LNG market. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. While economies of scale advances in liquefaction and transportation have enabled the use of LNG as a cost competitive source of gas supply in North America, those cost efficiencies are starting to be lost to higher input and construction costs. In anticipation of growing natural gas requirements in North America, there are numerous proposals to expand existing U.S. terminals and construct new LNG receiving facilities, including several proposed projects in Canada as summarized in Figure 20.

TABLE 4

Canadian Natural Gas Pipeline Proposals – 2006

Pipeline	Location	Capacity Increase (Bcf/d)	Proponents' Estimated Completion Date	Market Impacted
TransCanada Pipelines Limited – 2007 Eastern Mainline Expansion	Ontario, Québec	0.377	Late 2007	Central Canada Northeastern U.S.
TransCanada Pipelines Limited and TransCanada Keystone GP Ltd.	Saskatchewan, Manitoba	-0.5	2009/10	Transfer and conversion of gas pipeline assets to oil transportation service
Mackenzie Gas Pipeline	Mackenzie Delta, Northwest Territories to Alberta	1.2	2014	North America
Emera Brunswick Pipeline	New Brunswick	0.75	2008	Atlantic Canada, Northeastern U.S.
EnCana – Deep Panuke Pipeline	Nova Scotia	0.3	2010	Atlantic Canada, Northeastern U.S.
TransCanada Pipelines Limited / Trans Québec & Maritimes Pipeline Inc. – Gros Cacouna and Rabaska	Québec	0.5 0.5	2009/10	Central Canada Northeastern U.S.

FIGURE 20

Proposed Canadian LNG Projects

Location	Terminal	Company	Capacity (Bcf/d)	Proposed on Stream Date
1. Goldboro, Nova Scotia	Maple LNG	4 Gas BV and Suntera Canada Ltd.	1.0	2009
2. Saint John, New Brunswick	Canaport LNG	Repsol YPF and Irving Oil	0.8	2008
3. Rivière-du-Loup, Quebec	Gros Cacouna LNG	Petro-Canada and TransCanada Pipelines Ltd.	0.5	2009
4. Québec City, Quebec	Rabaska	Gaz Métro, Enbridge and Gaz de France	0.5	2009
5. Ridley Island, British Columbia	WestPac LNG	WestPac Terminals Inc.	0.3	2009
6. Emsley Cove, British Columbia	Kitimat LNG	Gavelston Energy	0.6	2010/11
7. Point Tupper, Nova Scotia	Statia LNG	Statia Terminals Canada Partnership	0.5	n/a
8. Saguenay, Quebec	Énergie Grande-Anse	Saguenay Port Authority and Énergie Grande-Anse Inc.	1.0	n/a

However, there is uncertainty around the number of LNG terminals that will be built in Canada as well as the potential effects that imported LNG will have on gas markets and the pattern of natural gas flow. The Canaport LNG facility in Saint John, New Brunswick is currently under construction and is scheduled to start service in 2008. Additional pipeline connections will also be required in most cases to connect the proposed LNG receiving terminals to existing natural gas pipeline infrastructure and natural gas markets.

These potential changes in Canada's natural gas supply and demand have important implications to both existing pipeline transportation systems and proposed new pipeline and LNG projects. Facilities which connect significant new supply from new sources such as the North and LNG or significant changes in regional demand (e.g. oil sands in Alberta and electricity generation in Ontario) will have the potential to influence markets and alter the utilization and gas flow on existing pipelines. In turn, these changes may impact the tolls and associated costs in using those pipelines. For example, introduction of new gas supply in Eastern Canada could result in greater utilization or flow reversals in regional pipelines and may also affect the flow of supply from traditional sources and pipelines. Similarly, greater demand in Alberta or Ontario can also alter the flow and availability of natural gas to adjacent regions.

In addition, the expected introduction of LNG close to Canadian markets has heightened the awareness of potential issues related to gas quality. Consequently, pipelines will need to work closely with their customers to establish gas quality standards and monitoring processes to ensure compatibility with existing equipment and end-use operation.

3.2 Oil

The expected growth in oil sands production is an increasingly important consideration to the pipeline industry as it determines which incremental markets to serve and how to expand the pipeline system efficiently since not all refineries are able to process a full range of crude oil types. Proposed refinery expansions and new construction in eastern Canadian are located close to the major petroleum product markets in the U.S. Northeast and have access to foreign crude oil supplies in addition to east coast offshore production. Other refineries in central Canada and the United States are proposing modifications which will enable them to process the heavier crude oil from oil sands production.

Looking to the future, the NEB expects that Canadian crude oil production will continue to increase, placing greater demands for transportation capacity to connect new supply and markets. Consequently, there are a number of proposals to provide additional pipeline capacity to transport crude oil and to provide additional supplies of diluent required to support growing oil sands operations. This additional pipeline capacity could enhance access to markets and increase market penetration. The North American demand for oil and refined products is also expected to increase, triggering a number of proposals for refinery expansions and the construction of new refineries in Canada and in the United States.

Table 5 provides a summary of the numerous proposals to expand or construct new oil pipeline capacity in Canada. These reflect the industry's outlook on growing oil sands production and the need for additional pipeline capacity to enhance market access. These proposals include pipelines to transport western Canadian crude oil to the west coast for delivery to Washington State and offshore markets, to the U.S. Midwest and southern PADD II and to the U.S. Gulf Coast (PADD III), and to provide new sources of diluent required for growing oilsands production. It is estimated that these pipeline projects comprise over \$23 billion in spending.

TABLE 5

Announced and Proposed Canadian Oil Pipelines and Expansions

Pipeline	Potential Filing Date	Capacity Increase (Mb/d)	Proponents' Estimated Completion Date	Market
Terasen (TPTM)				
Pump Station Expansion	Filed Feb 2006; Approved in Oct 2006	35	April 2007	PADD V
Anchor Loop - TMX1	Approved in Oct 2006	40	Nov. 2008	Offshore/Far East
Southern Option				
TMPL TMX2	N/A - Open Season unsuccessful	100	Mid 2010	PADD V
TMPL TMX3	N/A	300	2012	Offshore/Far East
Northern Option (TMX North)	N/A	400	2012 (uncertain)	PADD V Offshore/Far East
Enbridge Gateway (oil/diluent)	N/A	400/150	Between 2012 and 2014	PADD V Offshore/Far East Alberta (diluent line)
Pembina Spirit (diluent)	N/A	100	April 2009	Alberta
Enbridge Southern Lights	Filed 9 March 2007		2010	Alberta
Diluent return line		186		PADD II
Line 2 Expansion (oil)				PADD II
Edmonton to Cromer		47		PADD II
Cromer to Clearbrook				PADD II
TCPL (Keystone)	Filed Section 52 - Dec 2006	435	4Q2009	Southern PADD II and PADD III
Expansion / Extension to Cushing, OK		155	4Q2010	
Alberta Clipper	Filed May 30 2007	450	July 2010	Southern PADD II
Expansion	N/A	350	N/A	
Altex Energy	2008	250	2012	PADD III
Enbridge Spearhead Expansion	Open Season (2 Mar -2 April 2007)	65 100	2009 2011	Southern PADD II
Spearhead Looping	FERC only			
Enbridge (Southern Access)	FERC only	315		Midwest/Southern PADD II
Phase I		120	2008	
Phase II		148	2009	
Phase III Extension		47	N/A	

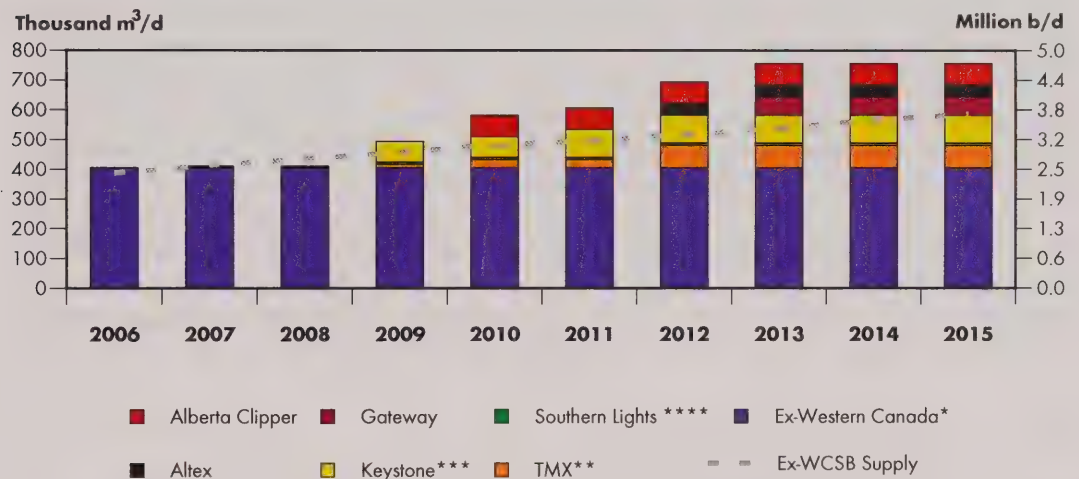
In the past year, the Board has also approved two crude oil pipeline related applications. In October 2006, the Board approved an application filed by TPTM to loop a portion of its pipeline between Hinton, Alberta and Rearguard, British Columbia. The project will increase capacity by 6 360 m³/d (40 Mb/d). It is expected to be in service by third quarter 2008.

In June 2006, the Board received an application by TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd. to transfer a portion of TransCanada's natural gas pipeline and associated facilities to crude oil service. The Keystone Project is a proposal to convert existing natural gas facilities in Canada and to construct a new crude oil pipeline in the U.S. to transport crude oil from Hardisty, Alberta to Patoka, Illinois. It would have a capacity of 69 000 m³/d (435 Mb/d) and is expected to be in-service in 2009 if approved. The Board approved the facilities transfer on 9 February 2007; however the TransCanada Keystone application for the construction of new oil facilities is still before the Board.

Looking beyond 2006, Figure 21 illustrates the NEB's forecast of crude oil production and the anticipated pipeline capacity available to transport crude oil and products from Western Canada on existing and proposed new facilities. This chart highlights that oil pipeline capacity is expected to be very tight in the next few years. It is expected that apportionment will occur in the fourth quarter 2007 and that this may be an issue for the next 18 months. As indicated by the figure, between now and 2009 crude oil pipelines out of Western Canada are expected to operate at capacity. The upstream industry is working together with pipeline companies to develop initiatives to reduce the impacts and/or eliminate apportionment. In 2009, TPTM would have an additional 12 000 m³/d (75 Mb/d) of capacity with its pumping station expansion and the looping; Southern Lights could add an additional 7 500 m³/d (47 Mb/d) to the Enbridge system from Cromer, Manitoba; and Keystone could be in-service if its application were approved by the Board.

FIGURE 21

Proposed Oil Pipeline Projects & NEB Forecast of Crude Oil Production



- * Total current crude oil pipeline capacity out of the WCSB assuming maximum heavy oil volumes.
- ** Pump Station expansion of 35 Mb/d by 2007 and looping 40 Mb/d by 3Q2008. TMX North would expand capacity by an additional 400 Mb/d but is not shown here.
- *** Keystone could be expanded by 155 Mb/d and extended to Cushing, Oklahoma by 4Q2010
- **** Net crude oil capacity increase of 47 Mb/d by 4Q2008

PIPELINE TOLLS & SHIPPER SATISFACTION

The Board utilizes a number of indicators to assess whether pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). This includes monitoring the stability of pipeline tolls as indicated through year-to-year variations in a benchmark toll for each of the major NEB-regulated pipelines; and direct shipper feedback received through response to the NEB's annual survey on pipeline services and via formal complaints. In addition, the frequency and acceptance of negotiated toll settlements, and the development of new or enhanced pipelines services are important indicators that there is alignment between the interest of pipeline companies and their shippers.

Historically, revenue requirements have been established using cost of service methodology, with some components for the return on and of invested capital. The revenue was then assigned to various rate categories and cost drivers for conversion into unit rates, or tolls. The revenue requirement and the toll setting methodology were matters for adjudication before the Board.

4.1 Negotiated Settlements

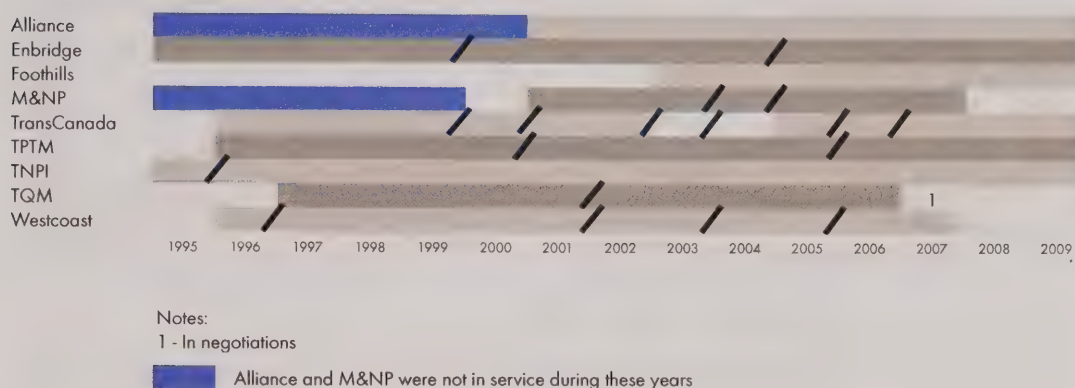
To improve the effectiveness of the regulatory process, the Board has supported the use of negotiated settlements since the mid-1980s as an alternative to toll hearings. In September 1988, the Board issued its first Guidelines for Negotiated Settlements. These guidelines were subsequently updated in August 1994 and revised again in June 2002 to provide flexibility when addressing contested settlements. With increasing use of negotiated settlements, adversarial hearings before the Board on tolls are becoming less frequent. Most of the pipeline companies still rely on cost of service methodology as a framework for the negotiated settlements.

As shown in Figure 22, all of the major pipelines regulated by the Board were operating under negotiated settlements during 2006. In late 2006, M&NP and its shippers successfully negotiated a one-year toll settlement for 2007. TransCanada has also recently negotiated a five-year settlement for 2007 to 2011 that was approved by the Board in May 2007. TPTM negotiated another five-year deal with its shippers for the years 2006 to 2010. TQM is currently operating under interim tolls which are based on a five-year settlement which expired on 31 December 2006. TQM is in discussion with its shippers regarding tolls for 2007 and future years. Westcoast Transmission and its shippers are currently in the second year of a two-year settlement for 2006 and 2007.

These negotiated settlements have resulted in a reduction in the regulatory burden for parties, both in terms of the time spent in hearings and the associated costs. They have also contributed to a better alignment of interests between pipeline companies and their shippers.

FIGURE 22

Negotiated Settlements Timeline



4.2 Pipeline Tolls Index

Stable and reasonable tolls are a key area of concern for users of the transportation and an indicator of the system's efficiency. The Board tracks year-to-year variations in tolls; the section below describes movements in the benchmark toll for each of the major pipelines it regulates (e.g., TransCanada's Eastern Zone toll or Westcoast's T-South Export toll). Under cost of service regulation, pipeline tolls can vary from year-to-year for various reasons. For example, a significant expenditure to modify or expand a system to meet shippers' needs could increase or decrease toll levels depending on the specific circumstances. Falling throughput or contract demand leading to lower capacity utilization could lead to a significant toll increase.

Natural Gas Pipeline Tolls

Figure 23 shows indexes of benchmark tolls⁴ for TransCanada's Mainline, Westcoast Transmission, Foothills, the TransCanada B.C. System (B.C. System), TQM, M&NP, Alliance, and the GDP deflator⁵ all normalized to the year 2006.⁶

The increase in TransCanada's benchmark toll between 1997 and 2004 is mainly attributed to a large amount of decontracting on the Mainline during that period, particularly after the startup of the Alliance pipeline in 2000. This toll tracked the GDP deflator fairly closely from 2001 to 2004. However, in 2005 and 2006 the toll fell, primarily due to increased contract demand: it remains below the level that it was in 2000.

Westcoast's tolls were relatively flat until 2004, when this toll increased by over 15 percent due to decontracting of firm services. Further reductions in volumes in 2006 caused a further 32 percent increase in 2006 tolls.

4 The benchmark tolls are: TransCanada Eastern Zone; Westcoast T-South Export; Foothills Zone 9; B.C. System Postage Stamp; TQM Saint Lazare to Trois-Rivières; M&NP Postage Stamp; and Alliance monthly demand toll.

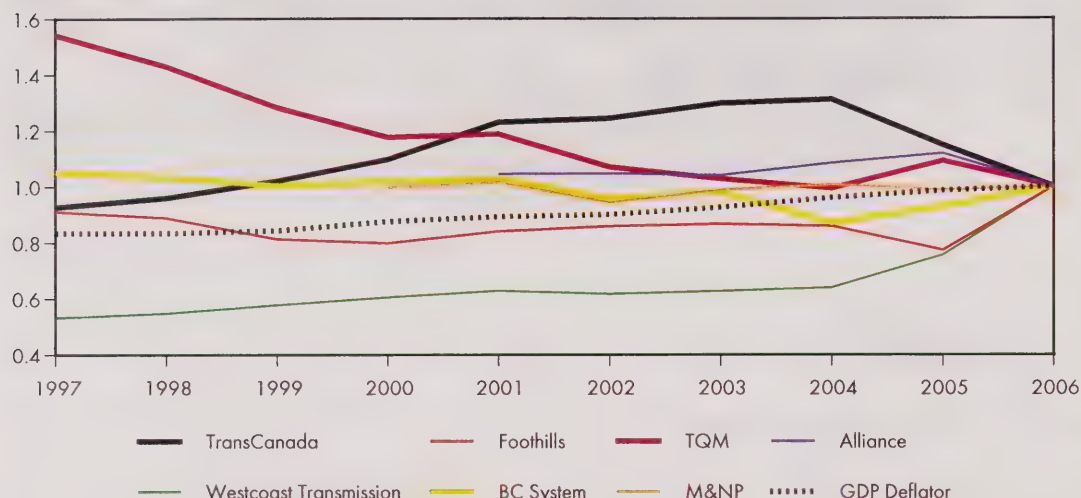
5 The implicit GDP deflator for 2006 is an estimate using actual data for the first half of the year and data estimated by Informetrica for the second half of the year.

6 Differing pipeline distances add to the challenges in comparing tolls between individual pipelines. Some normalization is required. Here the tolls are normalized only with respect to their own changes over time. The year of normalization is arbitrary; the most recent was selected as some tolls are only available for more recent years.

FIGURE 23

NEB-Regulated Natural Gas Pipeline Benchmark Tolls

Normalized to 2006 = 1.00



TQM's benchmark toll is below the 1997-1999 levels. This lower level is partly due to the Portland Natural Gas Transmission System (PNGTS) extension in 1999, which increased throughput over 30 percent from 1998. Foothills benchmark toll dropped in 1999 as a result of a cost-effective expansion of its system, but has increased in 2006 due to lower volumes and the end of the ten year period in 2005 for the deferred tax payback.

The B.C. System benchmark tolls in 2006 were close to the 1997 level. An (over 10 percent) increase in throughput volumes from 2003 reduced the 2004 benchmark toll on the B.C. System. M&NP and Alliance's benchmark tolls have been relatively constant since beginning operations at the end of 1999 and 2000 respectively.

Oil Pipeline Tolls

Figure 24 presents indexed values for the benchmark tolls of Enbridge, TPTM, TNPI, Express and the GDP deflator, normalized to the year 2006.⁷

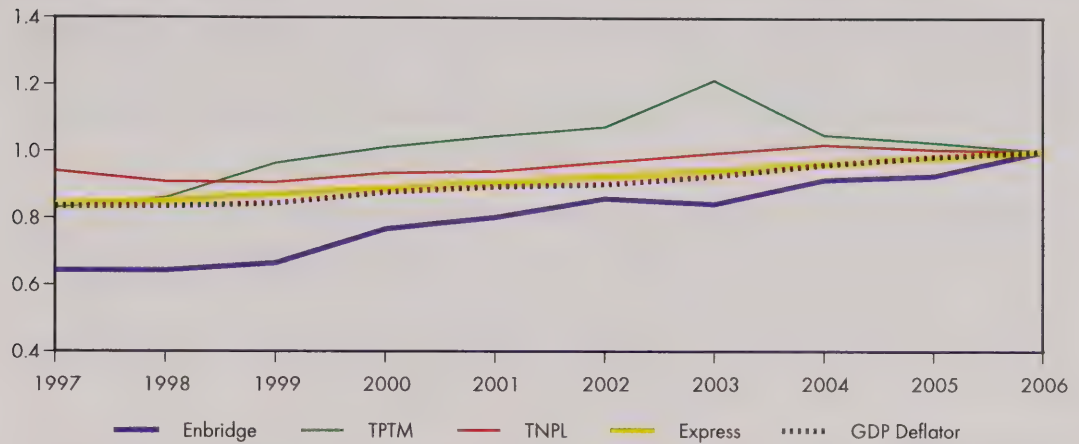
Enbridge's benchmark toll has risen fairly steadily over the period, growing at a faster pace than the GDP deflator, except for a drop in 2003. The tolls increased the most in 2000, 2004 and 2006. Under its negotiated settlement, Enbridge was able in the following year to recapture the revenue shortfall attributable to the lower throughput. The 2004 increase was primarily due to operating at lower capacity utilization with throughput not filling a recent capacity expansion. Higher fixed costs were spread across relatively lower volumes resulting in higher tolls.

TPTM's benchmark toll rose steadily from 1997 to 2003 but fell in the last three years. The large 1999 increase was due to throughput forecasts. During TPTM's first incentive toll settlement, tolls were calculated on forecast volumes. In 1999 the throughput forecast was 17.9 percent lower than the 1998 forecast, which led to a corresponding increase in the benchmark toll. In 2004, the benchmark toll dropped, primarily due to the disposition of deferrals for 2003 higher revenue. TNPI and Express's benchmark tolls moved roughly in line with the GDP deflator from 1997 to 2006.

⁷ The benchmark tolls are: Enbridge Edmonton to International Border near Chippewa; TPTM Edmonton to Burnaby; TNPI Oakville to Montreal; and Express 15-year.

FIGURE 24**NEB-Regulated Oil Pipeline Benchmark Tolls**

Normalized to 2006 = 1.00

**FIGURE 25****Oil and Natural Gas Pipeline Benchmark Tolls**

Normalized to 2006 = 1.00

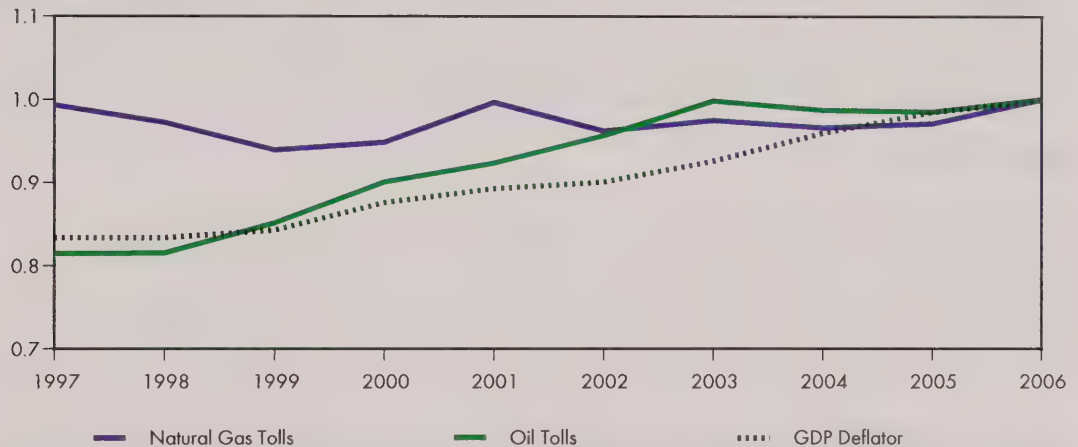
**Comparison of Gas and Oil Pipeline Tolls**

Figure 25 presents the GDP deflator with simple averages of the gas and oil benchmark pipeline tolls indices (reported in Figures 23 and 24).⁸ From 1997 to 2006, average natural gas pipeline tolls have been relatively flat despite the rise in the GDP deflator. Over the same period, oil pipeline tolls increased but the net increase over the period has matched the GDP deflator. Throughput volumes have been the primary driving factor in variations during the period.

⁸ No adjustments are made for the relative volume, capacity or length of the individual pipelines.

4.3 Shipper Satisfaction

4.3.1 NEB Pipeline Services Survey

The Board conducted its third annual Pipeline Services Survey in early 2007 to obtain direct feedback from the shippers of major NEB-regulated pipeline and midstream companies on the quality of service provided by those pipelines. The Board also used this survey to obtain feedback from shippers on the Board's regulatory performance with respect to tolls and tariffs.

To conduct this year's survey, the Board used a web-based survey tool, called Inquisite, which was sent to shippers directly via e-mail. For each survey received, shippers completed one response which reflects their company's corporate views on the services provided by the pipeline and midstream company being surveyed and on the services provided by the Board. The overall response rate for the survey was 27.0 percent, which was lower than last year's rate of 33.5 percent. The number of surveys sent out this year was 523, approximately 100 more than last year.

After analyzing the survey responses, the Board published a summary of the aggregate results on its website. They included the industry average and distribution of responses for each question and a summary of major themes. In addition, the Board provided each company and its shippers with detailed company-specific results including the average rating and distribution of responses for each question as well as the verbatim comments received from shippers, with the names of the respondents excluded.

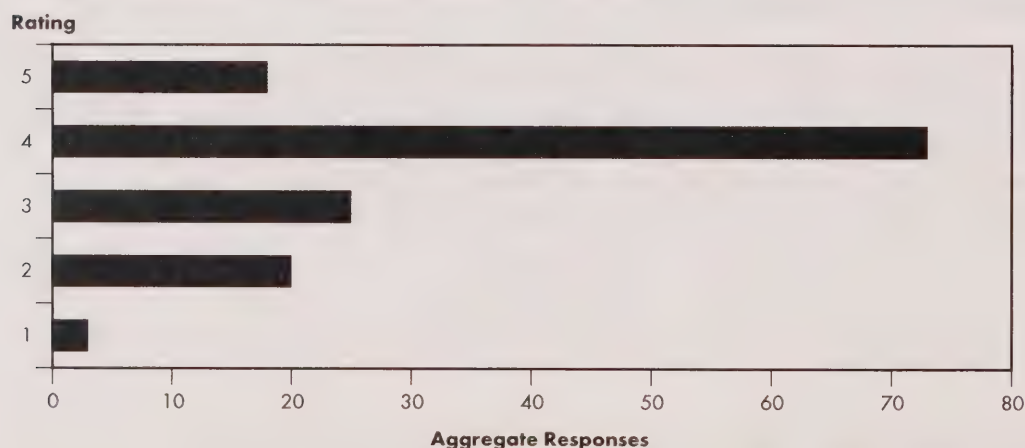
Appendix 3 provides the aggregate scores on all survey questions. For the complete report on the aggregate results, refer to [www.neb-one.gc.ca/Publications/Survey Results](http://www.neb-one.gc.ca/Publications/Survey%20Results).

Pipeline Services

Figure 26 shows the aggregate results for the survey question that asked shippers to rate their satisfaction with the overall quality of service provided by their pipeline/midstream companies over the last year (1 indicates "very dissatisfied" and 5 indicates "very satisfied"). The industry average score of 3.60 was slightly higher than the score of 3.57 in last year's survey. Sixty-five percent (65%) of the respondents gave their company a rating of satisfied or very satisfied on overall quality

FIGURE 26

Shipper Satisfaction on Pipeline Quality of Service



of service, compared to 58 percent last year. Based on these results, the Board is able to conclude that shippers again appear reasonably satisfied with the services provided by pipeline/midstream companies.

The three areas where shippers indicate that pipeline and midstream companies are doing very well are:

- Timeliness and accuracy of invoices and statements;
- Physical reliability of pipeline operations; and
- Satisfaction with transactional systems.

The three areas where shippers believe that companies could improve the most are:

- Reducing the level of transportation tolls or midstream charges;
- Exhibiting an attitude of continuous improvement and innovation; and
- Ensuring that settlements or tariff arrangements work well.

Feedback on the Board

The 2007 survey indicated that approximately 59 percent of shippers are either satisfied or very satisfied with the Board's performance with creating an appropriate regulatory framework and 55 percent of shippers are either satisfied or very satisfied with the Board's processes to resolve disputes. Both of these results were lower than in the 2006 survey. Two areas for improvement noted by shippers were for the Board to build its internal capacity to serve Canadians better and to provide effective regulatory processes that are more accessible to stakeholders and yield more timely decisions. Both of these areas are addressed in the Board's 2007-2010 Strategic Plan, which can be found at www.neb-one.gc.ca/AboutUs/strtgcpIn2007_2010_e.htm.

4.3.2 Formal Complaints

If shippers are unable to resolve concerns with the pipeline, they can bring a formal complaint to the Board. The complaint would then be dealt with through appropriate dispute resolution, a formal complaint process or, in some cases, the parties may be able to negotiate a solution to the concern. There was only one formal shipper complaint during the past year which involved the Board.

Several shippers on Cochin Pipe Lines Ltd. (Cochin)

In December 2006, Cochin filed for new rates to become effective 1 January 2007. The new rates reflected increases ranging from 91 to 580 percent across both Regular Volume Rates and Incentive Volume Rates and included a new toll segment from Detroit, Michigan to Windsor, Ontario. The Board received 11 letters from Cochin's shippers and interested parties indicating concern with the magnitude and timing of the rate increases. Shortly thereafter, Cochin initiated settlement discussions with its shippers and, in February 2007, filed a negotiated settlement and letters of support from many of its shippers. Following further negotiations with one opposing shipper, Cochin advised that it and the shipper had reached a resolution of the outstanding issue. Cochin's toll settlement was subsequently approved by the Board in May 2007.

4.3.3 Service Enhancements

On an ongoing basis pipelines may propose modifications to their services as circumstances and needs of their customers change or innovative ideas are brought forward. Normally, the pipeline and its shippers will discuss and agree upon proposed service enhancements in their tolls task force prior to submission to the Board and ultimate adoption. However, if the task force is unable to agree on the service, a party may still bring the issue directly to the Board.

Coral Energy Canada Inc. (Coral)

Coral applied to the Board to modify the Firm Transportation Risk Alleviation Mechanism (FT-RAM) pilot, a service enhancement proposed by TransCanada for its long haul contracts on the Mainline. In February 2006, The Board approved Coral's application which sought to extend FT-RAM credits to short-haul contracts held by the same shipper, which when combined with a long-haul contract forms a continuous long-haul on the TransCanada Mainline. The Board subsequently also approved amendments supported by an unopposed tolls task force resolution to extend the FT-RAM pilot project for an additional year.

TransCanada

In May 2006, TransCanada applied to the Board for approval of two new services on its Mainline, designed to meet the fluctuating demands of new gas-fired electric generation in Ontario. The Board has approved the implementation of these services; Firm Transportation - Short Notice (FT-SN) and Short Notice Balancing (SNB) and the proposed tolling method for FT-SN. However, the Board directed TransCanada to develop an alternate tolling method for SNB service.

Westcoast

After lengthy discussions with the Toll and Tariff Task Force on the possible decontracting on transmission facilities, Westcoast and its customers agreed to the following firm service enhancements, which were subsequently approved by the Board in RHW-1-2005 and implemented in 2006:

- Term differentiated rates (offering lower rates for longer term commitment) were taken up by about 25% of eligible volumes starting in January 2006.
- Authorized Over Run service which provides firm service customers with access to additional capacity at a higher priority than interruptible service was successfully utilized during a scheduling constraint in late 2006.
- Cross-corridor crediting was implemented on the various corridors on Westcoast's T-North system in 2006.

Moreover, to address periodic imbalance management issues, Westcoast, in collaboration with its shipper community, proposed a Supply Imbalance Management Strategy that was unanimously supported by its Toll and Tariff Task Force, and is expected to be implemented in 2007.

4.4 Chapter Summary

The following observations are made in this chapter:

- Shippers are able to resolve the majority of their tolling issues of interest with pipelines through the negotiated settlement process;

-
- Pipeline tolls have been relatively stable on average, although particular regional situations may cause greater variability in some areas;
 - Based on responses to the NEB Pipeline Services survey; shippers again appear reasonably satisfied with the services provided by pipeline/midstream companies.
 - There are few formal service complaints; and
 - Development of pipeline service enhancement continues.

The Board concludes that pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). Shippers are also reasonably satisfied with the role played by the Board itself, with some suggestions incorporated into the Board's own planning.

PIPELINE FINANCIAL INTEGRITY AND ABILITY TO ATTRACT CAPITAL

Pipeline companies must have adequate financial integrity to attract capital on reasonable terms and conditions to effectively maintain their systems and build new infrastructure to meet the market's evolving needs. The following sections review and discuss a number of the factors relevant to these areas, starting with the area over which the Board has the most direct influence.

5.1 Common Equity

A common equity ratio is defined as the percentage of common equity in a company's capital structure. This ratio is often used to evaluate a company's financial risk. Higher common equity ratios increase the likelihood of a company being able to meet its obligations.

Deemed Common Equity Ratios

The Board approves a deemed common equity ratio for the Group 1 pipeline companies that it regulates.⁹ When the Board approves a Group 1 pipeline company's tolls for a specified time period, it typically also approves a return on equity (ROE) and deems a common equity ratio for the regulated entity. Alternatively, some Group 1 pipeline companies successfully negotiate a comprehensive tolls settlement with their shippers, which may include capital structure and return on equity. In this instance, the Board still considers the overall settlement. Given the extent of negotiated settlements, many of the equity ratios have been determined by negotiation among the parties involved. Through this mechanism, the Board has influence over the operating profitability and financial risk of some Group 1 pipeline companies.

TABLE 6

Deemed Common Equity Ratios (Percent)

	2002	2006	2007
Alliance	30	30	30
Foothills	30	36	36
M&NP	25	25	29.27
TQM*	30	30	30
TransCanada B.C. System	30	36	36
TransCanada Mainline	33	36	40
Westcoast Transmission	30	35	36

* TQM's common equity ratio was specified in its negotiated settlement that expired on 31 December 2006.

Table 6 shows the deemed common equity ratio for some NEB Group 1 pipeline companies through adjudication or negotiation. TransCanada, Westcoast Transmission, B.C. System, and Foothills have increased their deemed common equity ratios between 2002 and 2006. The market considers these increases to be credit positive, lowering the financial risk of the pipeline companies.

⁹ A deemed common equity ratio is a notional capital structure used for rate-making purposes that may differ from a company's actual capital structure.

Return on Common Equity

Return on equity is commonly used to assess the operating profitability of a company. Financial markets define ROE as net income divided by common equity.

For NEB-regulated pipeline companies, ROE is the return on the equity portion of the rate base that is approved by the Board and is determined either through adjudication or negotiation. A higher ROE is typically preferred by investors.

Annually, the Board establishes an approved-ROE following the method outlined in RH-2-94. It is applicable to pipelines that the Board regulates, except those that have Board approved alternative rates. Achieved ROEs can vary from NEB-approved levels for various reasons, such as incentives, profit-sharing mechanisms and cost reductions.

Table 7 shows the achieved ROE for several NEB-regulated pipeline companies from 2002 to 2006 along with the ROE approved by the NEB in accordance with the RH-2-94 Formula¹⁰. As per their respective negotiated settlements, Enbridge, TPTM and Trans-Northern are not required to submit their Financial Surveillance Reports to the NEB, which would include achieved ROEs. Therefore, these pipeline companies are not included in Table 7. Other companies are included in Table 8, but are not subject to the RH-2-94 Formula ROE: Alliance and M&NP have negotiated ROEs with their shippers,¹¹ and Westcoast's Field Services Division is financially regulated on a complaint basis as described in the Framework for Light-handed Regulation (RHW-1-98). Fees for gathering and processing services are negotiated individually with shippers. TransCanada and TQM have negotiated settlements which use the RH-2-94 Formula as a basis and allow incentives causing some variations from the Formula rate.

The RH-2-94 Formula produced an ROE of 8.88 percent for 2006, falling each year since 2003 because of low interest rates. From 2002 to 2006, for pipeline companies subject to the RH-2-94

TABLE 7

Achieved ROEs and the RH-2-94 Formula ROE (Percent)

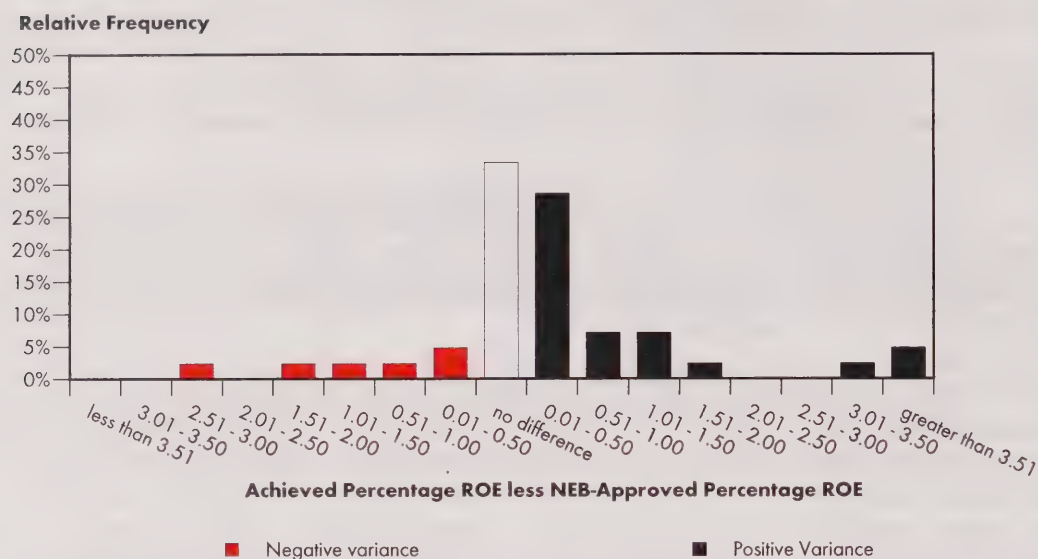
	2002	2003	2004	2005	2006
Transmission					
Alliance	11.25	11.25	11.25	11.25	11.25
Foothills	9.53	9.79	9.56	9.46	8.88
M&NP	12.95	12.31	13.75	14.31	14.68
TQM	9.80	10.21	9.84	9.92	8.99
TransCanada B.C. System	9.53	8.21	8.51	9.46	8.47
TransCanada Mainline	9.95	10.18	9.83	9.66	8.92
Westcoast Transmission*	13.44	12.93	10.28	10.82	9.16
NEB RH-2-94 Formula	9.53	9.79	9.56	9.46	8.88
Midstream					
Westcoast Field Services*	14.87	6.76	11.63	12.48	10.46

Source: NEB Surveillance and Annual Reports

* excluding CWIP (construction work in progress) and, in the case of Transmission, deferrals.

10 The formula used to determine the ROE for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, and later amended to eliminate rounding.

11 The settlements were subsequently approved by the Board. Alliance's settlement sets its ROE at 11.25 percent over this period. M&NP has a base return on equity of 12 percent for 2007; up to and including 2006 their base rate was 13 percent, with incentive potential.

FIGURE 27**Variance from NEB-Approved ROE for the Years 2001 to 2006**

Source: NEB Surveillance Quarterly and Annual Reports. Includes TransCanada Mainline and B.C. System, TQM, Westcoast Transmission system, and M&NP, as well as Foothills and Alliance which earn precisely their allowed ROE.

Formula ROE, only the TransCanada B.C. System has failed to earn an ROE at or above the Formula return in each year.

Most pipelines have, or have proposed, negotiated settlements. Three settlements have allowed ROEs that are different than the Formula ROE: Alliance, M&NP, and Trans-Northern. In the case of Alliance and M&NP, the ROE was fixed for an extended period. Other settlements use the RH-2-94 Formula as the allowed ROE and many of these settlements provide varying degrees of incentives to enable pipelines to earn more than the Formula ROE. As a result of the various incentives, most Group 1 pipelines have achieved actual ROEs that are greater than allowed ROEs. With the low interest rate environment, the RH-2-94 Formula produces an ROE of 8.46 percent for 2007.

Figure 27 charts the difference between achieved ROEs and NEB-approved ROEs for the TransCanada Mainline, the B.C. System, TQM, the Westcoast Transmission system, and M&NP. Also Foothills and Alliance are included; by their settlement their achieved ROEs equal their approved ROEs. From 2001 to 2006, pipeline companies (included in Figure 27) have met or exceeded their NEB-approved ROEs 86 percent of the time. The stability and predictability of returns is positive for both bondholders and equity investors. It also highlights that these pipeline companies, in many cases, have been able to meet or outperform approved levels through cost reductions, incentives and profit sharing mechanisms.

5.2 Financial Ratios

Financial ratios, based on financial statement information, can be useful in describing a company's performance and financial integrity. A financial ratio is most meaningful when the ratio of a particular company is compared with a benchmark or industry standard over time. A variety of ratios can be used to evaluate a company's liquidity, operating performance, growth potential, and risk. However, care must be exercised in the collection and interpretation of financial ratios. Reported financial information often pertains to a parent company, and includes non-regulated assets and/or assets from different industries.

The following sections specifically outline and discuss some ratios relating to the financial risk of certain companies with NEB-regulated pipelines.

Financial risk is the risk inherent in a company's use of debt and other obligations that have fixed payments. It differs from business risk which is the risk attributed to the nature of a particular business activity and for pipelines typically includes supply, market, regulatory, competitive and operating risks. Financial risk increases as the proportion of debt increases in relation to shareholders equity. An increase in debt may obligate a company to make more and larger fixed payments in the future. From a bondholder's perspective, a company with above average financial risk could have problems making interest payments. From an equity holder's perspective, a company's level of debt coverage gives some indication of the sustainability and value of the equity, and possible ability to pay dividends.

A company's financial risk can be described by ratios such as interest and fixed-charges coverage and cash flow-to-total debt and equivalents.

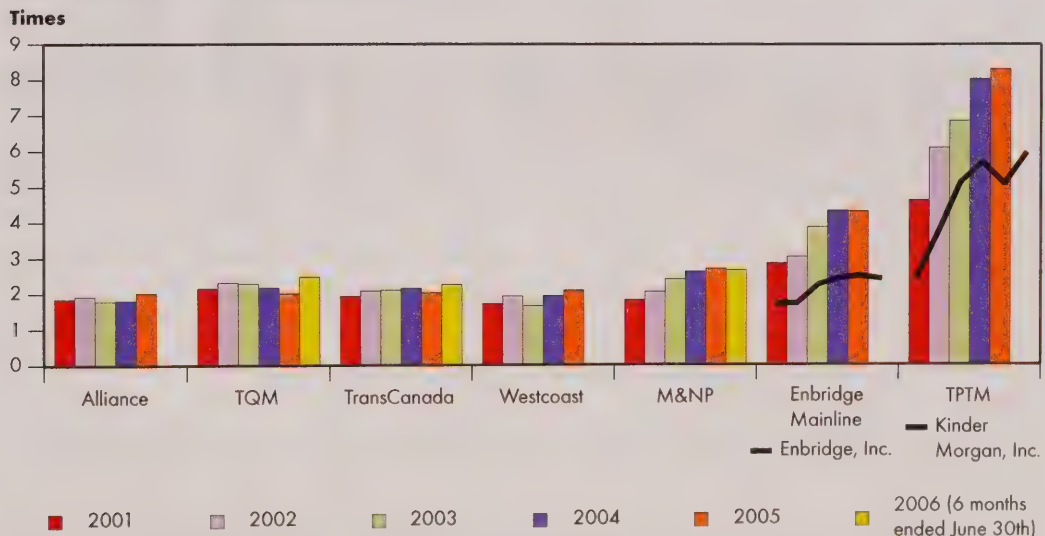
Interest and Fixed-Charges Coverage Ratios

An *interest coverage ratio* describes a company's ability to make interest payments and repay its debt obligations. It is defined as Earnings Before Interest and Taxes (EBIT) divided by interest charges. The metric presented below is similar: the *fixed-charges coverage ratio* describes the ability to make interest payments as well as other types of fixed payments a company is obligated to make. It is defined as earnings before interest, fixed charges and taxes divided by fixed-charges, including interest. Higher ratios indicate a higher likelihood that the company will be able to meet its obligations and, if all other things are equal, could indicate that it has unused borrowing capacity.

The fixed-charges coverage ratios for some NEB-regulated pipeline companies, as calculated by the Dominion Bond Rating Service (DBRS), are shown in Figure 28. Complete data are not available consistently for all companies: the Enbridge Mainline is shown in the block data, the consolidated company Enbridge Inc. is shown as the line. TPTM information was not available on a stand-alone

FIGURE 28

Fixed-Charges Coverage Ratios



Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge (Mainline) in 2006.

basis for 2006: the overlay line shown is its new owner, Kinder Morgan Inc. The average fixed-charges coverage ratio for the companies for which data is available is 2.42, which is a 6 percent increase year-over-year for those companies.¹²

No company saw its 2006 fixed-charges coverage ratio lower than its 2001 levels. From 2001 to 30 June 2006, the fixed-charges coverage ratio for the five natural gas pipeline companies shown increased modestly from a little under 2 times to around 2.2 by 2006. The two oil pipelines (Enbridge (Mainline) and TPTM, in each case representing the oil pipelines business unit) had higher ratios, which increased more rapidly. TPTM's fixed-charges coverage ratio has been higher, primarily due to a deemed common equity ratio of 45 percent (larger than its peers), which means it carried less debt, and had lower fixed payments. The continuing increases in fixed-charges coverage ratios for all companies is one metric signaling a decrease in the pipeline companies' financial risk, when considered as a group.

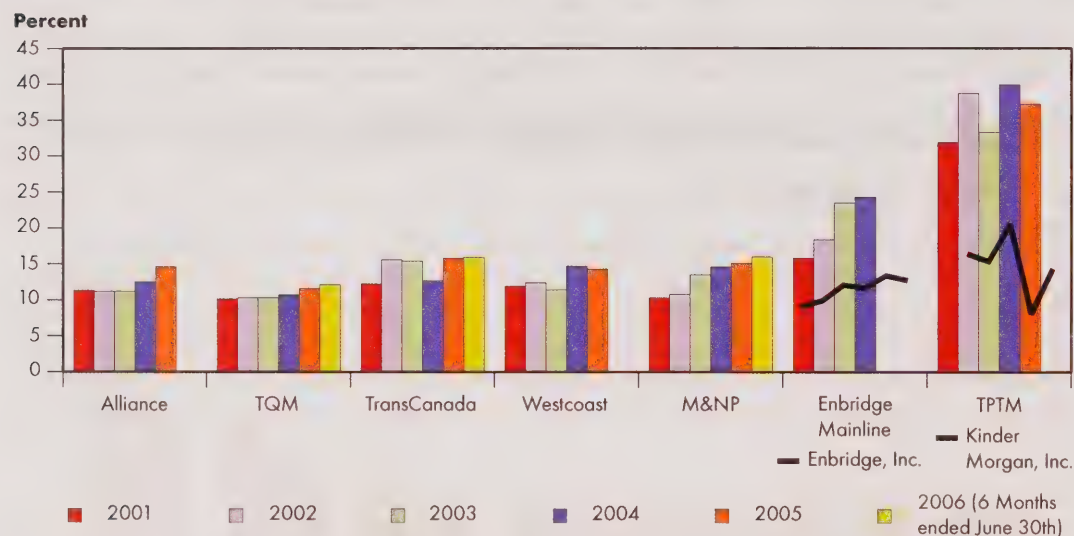
Cash Flow-to-Total Debt and Equivalents Ratio

The cash flow-to-total debt and equivalents ratio is another way of describing a company's ability to meet its debt obligations and fixed payments. It is defined as operating cash flow divided by total debt and debt equivalents. Again, higher ratios indicate an increased likelihood of a company being able to meet its obligations and indicate that it has greater borrowing capacity.

The cash flow-to-total debt and equivalents ratio for some NEB-regulated pipeline companies, as calculated by DBRS, are shown in Figure 29. As earlier noted, this ratio is not available for the pipeline units. The average cash flow-to-total debt and equivalents ratio for these companies was 14.2 percent for the partial year ending June 2006, a slight increase from the year before.¹³ TPTM's cash

FIGURE 29

Cash Flow-to-Total Debt and Equivalents Ratios



Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge (Mainline) in 2005 and 2006.

- 12 This average includes only Alliance, M&NP, TransCanada and Enbridge Inc.; this group had a simple average of 2.28 in 2005 and 1.93 in 2001. In last year's report, the average of 3.22 cited included other pipelines, such as TPTM.
- 13 The ratio is heavily influenced by the availability of TPTM data. In the 2006 report, the average ratio was 17 percent including data available for TPTM. Without TPTM the ratio was much more modest. Using only the companies which have data available this year, the average is 14.2 for 2006, slightly up from 14.0 for 2005 and up notably from 10.0 in 2000.

flow-to-total debt and equivalents ratio was higher than its peers for the same reason that its fixed-charges coverage ratio was higher.

On average, the cash flow-to-debt and equivalents ratio for these pipeline companies has grown by more than 20 percent from 2000 to 2006. The increase has been steady without any noteworthy periods of deterioration. The increase in this coverage ratio, and the consistent increase in cash flow-to-total debt and equivalents support the observation from the fixed-charges coverage that, on average, these pipeline companies' financial risk has been decreasing.

5.3 Credit Ratings

In Canada, pipeline credit ratings are determined by three independent credit rating agencies, Dominion Bond Rating Service (DBRS), Standard & Poor's (S&P), and Moody's. In general, credit ratings provide an assessment of the probability that a debt issuer will live up to its obligations and as such are an indication of the financial integrity of the rated company. Credit ratings assigned to a company generally reflect the consolidated operations of the entire company and not solely the regulated portion. Consequently, the credit rating for companies such as Enbridge, TransCanada and Westcoast that have both regulated and non-regulated operations may be influenced by its non-regulated operations. In addition, the credit ratings may be influenced to some extent by a parent company. Credit ratings are somewhat subjective in that a company's ratings are the expert opinion of the credit rating agency, which may result in different ratings by different agencies. See Appendix 4 for a comparison of the rating scales for DBRS, S&P, and Moody's.

DBRS

In assigning a credit rating to a particular company, DBRS attempts to consider all meaningful factors that could impact the risk of maintaining timely payments of interest and principal in the future. The key credit considerations will vary industry by industry; however, some of the common factors that are considered for most ratings are: core profitability, asset quality, strategy and management strength, and the financial and business risk profile.

For pipelines, the following specific factors are also considered in deriving the credit ratings: regulatory factors, competitive environment, supply and demand considerations, and regulated versus non-regulated activities. The credit ratings for most Group 1 pipeline companies shown in Table 8

TABLE 8

DBRS Credit Rating History

Pipeline	2002	2003	2004	2005	2006	Current
Alliance	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb
Enbridge Pipelines	A(high)	A(high)	A(high)	A(high)	A(high)	A(high)/Stb
Express ¹	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb
M&NP	A	A	A	A	A	A/Stb
TQM	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb
TransCanada	A	A	A	A	A	A/Stb
Trans Mountain	A(low)	A(low)	A(low)	A(low)	repaid	repaid
Trans-Northern	NR	NR	NR	A(low)	A(low)	A(low)/Stb
Westcoast ²	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb

1 Senior secured

2 Unsecured debentures

NR Not rated

indicates that the ratings have remained stable from 2002 to the present, varying from A(low) to A(high), and there have been no recent rating changes.

Standard & Poor's

An S&P credit rating reflects a borrower's capacity and willingness to meet its financial commitments on a timely basis. S&P bases its ratings on the overall creditworthiness of a consolidated company. Therefore, the rating of a wholly-owned subsidiary, in the absence of meaningful ring-fencing measures, generally reflects the creditworthiness of the parent.

In S&P's rating methodology, a company rated 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and

economic conditions than companies in higher-rated categories. A company rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the company to meet its financial commitments.

The rating histories for several Group 1 pipeline companies are provided in Table 9. The table illustrates that the ratings have remained stable from 2002 to the present, varying from 'BBB+' to 'A-'. There have been two recent rating changes. First, the credit rating on the long-term debt of Westcoast Energy Inc. was upgraded to 'BBB+' in January 2007 from 'BBB', which had been in place since February 2004. The rating change was based on the ownership change at the parent company level that occurred effective 2 January 2007 when Duke Energy Corporation completed the spin-off of its natural gas business (including Westcoast) to Spectra Energy Corporation, a new publicly traded company. Second, in April 2007, S&P revised its outlook on TransCanada from 'negative' to 'stable'. The negative outlook on TransCanada's credit rating had been in place since December 2002, and was initially associated with TransCanada's acquisition of a significant interest in Bruce Power in February 2002. S&P noted that TransCanada's recent acquisition of ANR and its investment in the Keystone oil pipeline project provide a stabilizing offset to the declining rate base and lower return on equity from its traditional business.

Both DBRS and S&P have expressed an opinion at various times that the ROE awarded through the RH-2-94 Formula and the deemed equity ratios awarded by the Board are low by international standards. Nonetheless, the ratings assigned by these credit rating companies indicate that NEB-regulated companies are all rated investment grade.

TABLEAU 9

S&P Credit Rating History

Pipeline	2002	2003	2004	2005	2006	Cote actuelle
Pipelines Enbridge	A-/Neg	A-/Stb	A-/Stb	A-/Stb	A-/Stb	A-/Stb
M&NP ¹	A/Stb	A/Stb	A/Stb	A/Stb	A/Stb	A/Stb
TQM	BBB+/Stb	BBB+/Stb	BBB+/Stb	BBB+/Stb	BBB+/Stb	BBB+/Stb
TransCanada	A-/Watch/Neg	A-/Watch/Neg	A-/Watch/Neg	A-/Neg	A-/Neg	A-/Stb
Trans Mountain	BBB+/Neg	BBB/Stb	BBB/Stb	BBB/Stb	debt repaid	debt repaid
Westcoast ²	A/Stb	BBB+/Stb	BBB+/Stb	BBB/Watch/Neg	BBB/Stb	BBB+/Stb

1 Senior secured

2 Unsecured debentures

Moody's

Moody's credit analysis focuses on the fundamental factors and key business drivers relevant to an issuer's long-term and short-term risk profile. The foundation of Moody's methodology rests on two basic considerations:

- The risk to the debt holder of not receiving timely payment of principal and interest on the specific debt security.
- A comparison of the level of risk with that of all other debt securities.

Like S&P, Moody's focuses its ratings on the overall creditworthiness of the consolidated entity. In so doing, Moody's measures the ability of an issuer to generate cash in the future, thus its primary focus is on the predictability of future cash generation. This determination is built on an analysis of the individual issuer and of its strengths and weaknesses compared to those of its peers worldwide. An examination of factors external to the issuer is also conducted, including industry- or country-level trends that could impact the entity's ability to meet its debt obligations. Of particular concern is the ability of management to sustain cash generation in the face of adverse changes in the business environment.

The rating histories for several Group 1 pipeline companies are provided in Table 10. All of Moody's ratings placed the pipelines in the investment grade category, specifically rated 'medium grade' to 'upper-medium grade'.

There has been one recent rating change by Moody's. In March 2007 Moody's downgraded the ratings on the senior unsecured debt of Enbridge Inc. one notch to Baa1 from A3.¹⁴ Moody's stated that the one notch downgrade was based on concerns relating to the company's weak financial profile, the complexity of its organizational and capital structure, and the scope and financial impact of the company's substantial organic growth plans.

5.4 Comments by the Investment Community

Access to capital market is necessary for pipeline companies to maintain and, potentially, expand their systems as the needs of the transportation market changes. Board staff met with credit rating analysts, equity analysts, and suppliers of capital such as insurance and pension funds to discuss their views on the ability of NEB-regulated pipeline companies to access capital markets as well as their views on transportation markets and the current regulatory environment in Canada.

TABLE 10

Moody's Credit Rating History

Pipeline	2002	2003	2004	2005	2006	Current
Alliance ¹	A3	A3	A3	A3	A3	A3
Enbridge Inc.	A2	A3	A3	A3	A3	Baa1
Express ²	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1
M&NP ²	A1	A1	A1	A2	A2	A2
TransCanada ¹	A2	A2	A2	A2	A2	A2

1 Unsecured debentures

2 Senior secured

14 Enbridge Inc. is the parent company of Enbridge Pipelines Inc., which owns the Enbridge Mainline. Unlike DBRS and S&P, Moody's does not rate the debt issued by Enbridge Pipelines Inc.

There was a consensus among parties that there is substantial liquidity in both domestic and export global capital markets. Solid economic growth in recent years, low interest rates, the accumulation of capital in pension funds and the ability of private equity funds to borrow large sums at low rates from finance companies were among the reasons cited for the current situation, which was characterized as ‘a lot of money chasing too few assets’. Regulated businesses, along with infrastructure and real estate, were seen as particularly attractive investments. It was noted that the federal tax changes made in October 2006 with respect to income trusts and increases in the dividend tax credit also increased demand for shares of dividend paying companies like financials, utilities and pipelines, at least temporarily.

Given this environment, there was agreement that NEB-regulated pipelines have not had difficulty accessing equity or debt markets. The parent companies of TransCanada PipeLines Limited and Enbridge Pipelines Inc. recently went to the equity market and collectively raised more than \$2 billion. Both companies have also had substantial debt issues recently. However, some parties expressed concern that on a stand-alone basis the regulated entities themselves might have difficulty attracting capital given low ROEs. Others felt that the regulated entities would be able to attract capital but that the terms under which they did so may be more costly than for the consolidated entity.

Again this year the investment community noted that price-to-earnings ratios of utilities in Canada have been higher than those in the U.S. because of large energy infrastructure investment opportunities, a more stable regulatory environment and global interest in Canadian stocks. While there is currently substantial liquidity, it was noted that capital markets could change and this could happen very quickly and result in considerable volatility.

Many analysts expressed support for a formulaic approach to determining ROEs because of the transparency, stability and predictability that this method provides. However, a number expressed the view that the ROE resulting from the formula was too low, and contend that they are much lower than regulated ROEs in the U.S. and U.K. While views ranged widely on this issue, some felt that the typically lower ROEs in Canada were not justified by the differences in risk for Canadian companies compared to FERC-regulated pipelines. Some parties suggested it was time for the Board to revisit the ROE Formula.

5.5 Chapter Summary

The observations made in this chapter may be summarized as follows:

- Fixed-charges and cash flow-to-total debt and equivalents coverage ratios have increased since 2001;
- Deemed common equity ratios have increased since 2001;
- Achieved ROEs have in most cases been greater than or equal to their NEB-approved levels since 2001;
- Approved ROEs have been predictable, but declining and may now be too low;
- Credit ratings continue to be investment grade; and
- The investment community views NEB-regulated companies as having access to capital markets at this time of significant liquidity, but noted that market conditions can change rapidly and that on a stand-alone basis the regulated entities themselves may have difficulty attracting capital given current ROEs.

In general, these observations signal that, currently pipelines companies have adequate financial strength to attract capital on reasonable terms and conditions.

CONCLUSIONS

Based on the criteria identified in the Introduction to this report, the Board believes that the Canadian hydrocarbon transportation system continues to work effectively.

1. **There is adequate capacity in place on existing natural gas pipelines.** The price differentials and capacity utilization charts indicate that most NEB-regulated gas pipelines have some excess capacity, even during the peak winter season. The existence of some excess capacity out of the WCSB has provided suppliers with the flexibility to access markets of their choice at most times. Proposed pipeline projects are mainly directed towards providing connection to new supplies or addressing bottlenecks in the market area.

Capacity remains very tight on oil pipeline systems. While the capacity utilization indicators show that there was spare capacity on some of the pipelines in 2006, this was partially due to facility outages reducing the amount of crude oil or products to be transported. It is likely that export crude oil pipelines out of Western Canada may experience periods of apportionment by the fourth quarter 2007, and this may continue for the next 18 months. As indicated by Figure 21, no significant pipeline capacity is expected to be added between now and 2009. The industry and the pipeline companies are working together to develop a number of initiatives to reduce and/or eliminate the impacts of apportionment.

The number of announced and proposed pipeline and expansions, and the transfer of under-utilized gas pipeline facilities on the TransCanada Mainline to transportation of crude oil, illustrates that the hydrocarbon transportation systems are responding and have the ability to make adjustments to pipeline capacity as market conditions change.

2. **Shippers continue to indicate that they are reasonably satisfied with the services provided by pipelines.** Once again, shippers rate the physical reliability of pipeline operations highly and express the most concern around the level of pipeline tolls.
3. **NEB-regulated pipeline companies are financially sound and have been able to attract capital on reasonable terms and conditions.** While it is recognized that some of the data and indicators reviewed are for the consolidated operations of pipeline companies, the investment community views NEB-regulated companies as having access to capital markets at this time of significant liquidity. However, the investment community also noted that market conditions can change rapidly and that on a stand-alone basis the regulated entities themselves may have difficulty attracting capital given current ROEs.

As identified in Chapter 3, there are a significant number of pipelines proposed to ensure that the Canadian transportation system has sufficient capacity to deliver the additional volumes of oil and natural gas to serve new and growing markets. The challenge for the pipeline transportation industry is to put appropriate capacity in service corresponding with changes in production and market requirements. For this to happen there must be adequate and predictable lead times to achieve

sufficient market support from amongst competing proposals, obtain regulatory approvals, arrange financing, mobilize labour and materials, and construct facilities.

A key component and ongoing challenge from the NEB's perspective is to provide, in a timely manner, a fair and effective process that does not distort the market place investment decisions. This may involve ongoing efforts to coordinate regulatory activities with other jurisdictions and to provide clear regulatory processes with predictable timelines. New investment can be frustrated when unexpected regulatory hurdles create delays or unpredictable timelines which may introduce uncertainty from changing supply and market conditions and business risk. Further, unnecessary construction delays, for both expansions and new pipelines, can be costly to both energy consumers and producers as the development of new supplies is constrained. Given the large capital outlay and the long-term nature of these investments, market participants seek to ensure that the optimal decisions are made.

The Board recognizes that this report represents only a snapshot in time and does not include a comparison with or to pipeline transportation systems in other jurisdictions. As part of its mandate, the Board will continue to monitor the effectiveness of the transportation system and will continue to meet with parties to gain an understanding of all perspectives on this issue. The Board welcomes feedback on the measures and conclusions in this report and also welcomes suggestions for improvements to future reports.

The Board thanks those companies and organizations that directly or indirectly provided the information found in this report, including those that actively participated in the Pipeline Services Survey.

STAKEHOLDER CONSULTATION

Alliance Pipeline Ltd.
BMO Nesbitt Burns
Canadian Association of Petroleum Producers
Canadian Energy Pipeline Association
Canadian Gas Association
Canaccord Adams
Caisse de dépôt et placement du Québec
CIBC World Markets
Cochin Pipe Lines Ltd.
Dominion Bond Rating Service
Enbridge Pipelines Inc.
Express Pipeline Limited Partnership
Foothills Pipe Lines Ltd.
Industrial Gas Users Association
Kinder Morgan Canada Inc.
Maritimes and Northeast Pipeline
Moody's Investor Services
Ontario Teachers' Pension Plan
RBC Capital Markets
Scotia Capital
Standard & Poor's
Sun Life Financial
Terasen Pipelines Inc.
Terasen Pipelines (Trans Mountain) Inc.
Trans-Northern Pipeline Inc.
Trans Québec & Maritimes Pipeline Inc.
TransCanada PipeLines Limited
Union Gas Limited
Westcoast Energy Inc.

GROUP 1 AND GROUP 2 PIPELINES

Regulated by the NEB As of 31 December 2006

Group 1 Gas Pipelines

Alliance Pipeline Ltd.
Foothills Pipe Lines Ltd.
Gazoduc Trans Québec & Maritimes Inc.
Maritimes & Northeast Pipeline Management Ltd.
TransCanada PipeLines Limited
TransCanada PipeLines Limited, B.C. System
Westcoast Energy Inc.

Group 1 Oil and Products Pipelines

Cochin Pipe Lines Ltd.
Enbridge Pipelines Inc.
Enbridge Pipelines (NW) Inc.
Terasen Pipelines (Trans Mountain) Inc.
Trans-Northern Pipelines Inc.

Group 2 Natural Gas and Natural Gas Liquids Pipelines

AltaGas Pipeline Partnership
Apache Canada Ltd.
ARC Resources Ltd.
Bear Paw Processing Company (Canada) Ltd.
BP Canada Energy Company
Burlington Resources Canada (Hunter) Ltd.
Canada Customs and Revenue Agency
Canadian Natural Resources Limited
Canadian-Montana Pipe Line Corporation
Centra Transmission Holdings Inc.
Champion Pipeline Corporation Limited
Chief Mountain Gas Co-op Ltd.
DEFS Canada L.P.
Delphi Energy Corporation
Devon Canada Corporation
Devon Energy Canada Corporation

DR Four Beat Energy Corp.
Echoex Energy Inc.
EnCana Border Pipelines Limited
EnCana Ekwan Pipeline Inc.
EnCana Oil & Gas Co. Ltd.
EnCana Oil & Gas Partnership
Enermark Inc.
ExxonMobil Canada Properties
Forty Mile Gas Co-op Ltd.
Huntingdon International Pipeline Corporation
Husky Oil Operations Ltd.
Kaiser Exploration Ltd.
KEYERA Energy Ltd.
Many Islands Pipe Lines (Canada) Limited
Marauder Resources West Coast Inc.
Mid-Continent Pipelines Limited
Minell Pipeline Limited
Murphy Canada Exploration Company
Murphy Oil Company Ltd.
Nexen Inc.
Niagara Gas Transmission Limited
Northstar Energy Corporation
NuVista Energy Ltd.
Omimex Canada, Ltd.
Paramount Transmission Ltd.
Peace River Transmission Company Limited
Pengrowth Corporation
Penn West Petroleum Ltd.
Petrovera Resources Ltd.
Pioneer Natural Resources Canada Inc.
Portal Municipal Gas Company Canada Inc.
Prairie Schooner Limited Partnership
Profico Energy Management Ltd.
Renaissance Energy Ltd.
St. Clair Pipelines Management Inc.
Shiha Energy Transmission Ltd.
Suncor Energy Inc.
Sword Energy Limited
Talisman Energy Inc.
Taurus Exploration Canada Ltd.
Union Gas Limited
Vault Energy Inc.
Vector Pipeline Limited Partnership
County of Vermillion River No. 24 Gas Utility
2193914 Canada Limited
806026 Alberta Ltd.
1057533 Alberta Ltd.

Group 2 Oil and Products Pipelines

Amoco Canada Petroleum Company Ltd.
Aurora Pipe Line Company
Berens Energy Ltd.
BP Canada Energy Company
Dome Kerrobert Pipeline Ltd.
Dome NGL Pipeline Ltd.
Duke Energy Empress L.P.
Enbridge Pipelines (Westspur) Inc.
Ethane Shippers Joint Venture
Express Pipeline Limited Partnership
Genesis Pipeline Canada Ltd.
Glencoe Resources Ltd.
Husky Oil Limited
Imperial Oil Resources Limited
ISH Energy Ltd.
Montreal Pipe Line Limited
Murphy Oil Company Ltd.
NOVA Chemicals (Canada) Ltd.
PanCanadian Kerrobert Pipeline Ltd.
Paramount Transmission Ltd.
Penn West Petroleum Ltd.
Plains Marketing Canada, L.P.
PMC (Nova Scotia) Company
Pouce Coupé Pipe Line Ltd. (as agent and general partner of the Pembina North Limited Partnership)
Provident Energy Pipeline Inc.
Renaissance Energy Ltd.
SCL Pipeline Inc.
Shell Canada Products Limited
Sun-Canadian Pipe Line Company
Taurus Exploration Canada Ltd.
Yukon Pipelines Limited
1057533 Alberta Ltd.

PIPELINE SERVICES SURVEY

Aggregate Results

Below are the aggregate responses for each question in the survey. Respondents were asked to rate their satisfaction with the services they receive on a scale of 1 to 5, where 1 indicates “Very dissatisfied” and 5 indicates “Very satisfied”. See the Board’s website for the complete details

1. How satisfied are you with the physical reliability of the pipeline company’s operations?

1	2	3	4	5	Average
4	18	12	74	31	3.79

2. How satisfied are you with the quality, flexibility and reliability of the pipeline company’s transactional systems (nominations, bulletin boards, reporting, contracting, etc)?

1	2	3	4	5	Average
0	24	16	75	22	3.69

3. How satisfied are you with the timeliness and accuracy of the pipeline company’s invoices and statements?

1	2	3	4	5	Average
7	7	14	75	31	3.87

4. How satisfied are you with the timeliness and usefulness of operations information (outages, available capacity, scheduled maintenance, flows, etc) provided by the pipeline company?

1	2	3	4	5	Average
3	17	21	79	19	3.68

5. How satisfied are you with the timeliness and usefulness of commercial information (tolls, service changes, new services, contract information, etc) provided by the pipeline company?

1	2	3	4	5	Average
7	13	34	70	15	3.53

6. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?

1	2	3	4	5	Average
10	30	36	51	11	3.17

7. How satisfied are you with the accessibility and responsiveness of the pipeline company to shipper issues and requests?

1	2	3	4	5	Average
9	22	32	54	21	3.41

8. How satisfied are you that the pipeline company works towards fair and reasonable solutions when resolving issues?

1	2	3	4	5	Average
6	20	37	54	19	3.44

9. How satisfied are you with the suite of services offered by the pipeline company?

1	2	3	4	5	Average
4	13	40	67	10	3.49

10. How satisfied are you with the level of this pipeline company's tolls in relation to the transportation services your company receives?

1	2	3	4	5	Average
7	26	42	53	4	3.16

11. How satisfied are you with the collaborative processes (negotiations or task force meetings) utilized by this pipeline company?

1	2	3	4	5	Average
11	16	38	45	14	3.28

12. How satisfied are you that the current negotiated settlement agreement or tariff arrangements work well to provide fair outcomes?

1	2	3	4	5	Average
11	8	47	52	5	3.26

13. How satisfied are you with the OVERALL quality of service provided by the pipeline company over the last calendar year?

1	2	3	4	5	Average
3	20	25	73	18	3.60

14. On an overall basis, has the pipeline company's quality of service in the last year:

Improved	18	13%
Remained the Same	100	72%
Decreased	20	15%
Total	138	100%

15. What are the things that this pipeline company does well?

16. What are the things that this pipeline company could do better?

-
17. How satisfied are you that the NEB has established an appropriate regulatory framework in which negotiated settlements for tolls and tariffs can be reached?

1	2	3	4	5	Average
4	10	39	67	9	3.52

18. When toll and tariff matters are not resolved through settlement, how satisfied are you with the Board's processes to resolve disputes?

1	2	3	4	5	Average
4	6	39	53	7	3.49

19. What could the Board be doing to improve its processes through which tolls and tariffs are determined?

DEBT RATING COMPARISON CHART

This chart provides a comparison of the rating scales used by Dominion Bond Rating Service (DBRS), Standard and Poor's (S&P), and Moody's when rating long-term debt.

Standard & Poor's also provides a Rating Outlook that assesses the potential direction of a long-term credit rating over the intermediate to longer term. A 'Positive' outlook means that a rating may be raised; a 'Negative' outlook means that a rating may be lowered; and a 'Stable' outlook means that a rating is not likely to change.

Credit Quality	DBRS	S&P	Moody's
Investment Grade			
Superior / High grade	AAA	AAA	Aaa
	AA (high)	AA+	Aa1
	AA	AA	Aa2
	AA (low)	AA-	Aa3
Good / Upper Medium	A (high)	A+	A1
	A	A	A2
	A (low)	A-	A3
Adequate / Medium	BBB (high)	BBB+	Baa1
	BBB	BBB	Baa2
	BBB (low)	BBB-	Baa3
Non-Investment Grade			
Speculative	BB (high)	BB+	Ba1
	BB	BB	Ba2
	BB (low)	BB-	Ba3
Highly Speculative	B (high)	B+	B1
	B	B	B2
	B (low)	B-	B3
Very Highly Speculative	CCC	CCC	Caa1
	CC	CC	Caa2
	C	C	Caa3
	D	D	Ca
			C

Note: DBRS and S&P ratings in the CCC category and lower also have subcategories "high/+" and "low/-" and the absence of "high/+" and "low/-" designation indicates the rating is in the "middle" of the category.



GOAL 3

**Canadians benefit from efficient
energy infrastructure and markets.**

